BASIN ELECTRIC POWER COOPERATIVE

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RECEIVED

JUN 27 2012

PUBLIC SERVICE COMMISSION

June 25, 2012

Mr. Kevin Cramer, Commissioner
North Dakota Public Service Commission
Capitol Building
600 E. Boulevard Avenue
Bismarck, ND 58505

Dear Mr. Cramer:

Pursuant to the requirements of the North Dakota Energy Conversion and Transmission Facility Siting Act, Basin Electric Power Cooperative hereby submits its Ten Year Plan.

Enclosed is an original and 10 copies of the plan.

Sincerely,

Andrew M. Serri
CEO & General Manager

vlw
ATTACHMENT

1 **PU-12-414** Filed: 6/27/2012 Pages: 47
2012 Ten year plan

Basin Electric Power Cooperative

Andrew Serri, CEO and General Manager

STATE OF NORTH DAKOTA)
)
COUNTY OF BURLEIGH)

AFFIDAVIT OF MAILING

I hereby certify that the following list contains the names and last address of each designated state agency and/or state official given notice of filing of the Basin Electric Power Cooperative Ten Year Plan pursuant to the Rules and Regulations of the North Dakota Public Service Commission governing the Siting of Energy Conversion and Transmission Facilities. I hereby certify that I have, by depositing letters of notice with the United States Postal Service, caused notice to be given all such state agencies and state officials that Basin Electric Power Cooperative has filed their Ten Year Plan with the North Dakota Public Services Commission.

Name	Last Known Address
See Exhibit A Attached	See Exhibit A Attached

Matthew Stoltz
Signature

On this 25TH day of June, 2012, Matthew Stoltz known to me, under oath deposed and said the above Affidavit of Mailing is true and correct.

MICHELLE WIEDRICH
Notary Public
State of North Dakota
My Commission Expires August 6, 2015

Michelle Wiedrich
Notary Public

Mail to: Public Service Commission
600 E. Blvd. Ave.; Capitol Building
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EXHIBIT A

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BASIN ELECTRIC
POWER COOPERATIVE

NORTH DAKOTA TEN-YEAR PLAN

2012

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INTRODUCTION

Basin Electric Power Cooperative is a regional rural electric wholesale power supplier headquartered at 1717 East Interstate Avenue, Bismarck, North Dakota. The region served by Basin Electric includes all or portions of nine states encompassing Montana, Wyoming, Colorado, North Dakota, South Dakota, Nebraska, Minnesota, Iowa and New Mexico. Basin Electric owns and operates or otherwise jointly shares energy conversion and transmission facilities throughout this region. Basin Electric is the parent company to eight subsidiaries, Basin Cooperative Services, Dakota Gasification Company, Dakota Coal Company, Montana Limestone Company, Basin Telecommunications Inc, Souris Valley Pipeline LTD., PrairieWinds ND 1 Inc., and PrairieWinds SD 1 Inc. A ten-year plan for Dakota Gasification Company will be submitted under separate cover by Dakota Gasification Company.

SECTION A: EXISTING ENERGY CONVERSION FACILITIES

Basin Electric owns all or portions of thirteen existing energy conversion facilities. Four of these facilities are in North Dakota; the Antelope Valley Station near Beulah; the Leland Olds Station at Stanton; PrairieWinds 1 near Minot; and the Minot Wind Project near Minot. Other existing energy conversion facilities outside of North Dakota are the Laramie River Station at Wheatland, Wyoming; the Wyoming Distributed Generation in Wyoming; the Dry Fork Station near Gillette, Wyoming; the Spirit Mound Station at Vermillion, South Dakota; the Chamberlain Wind Project at Chamberlain, South Dakota; the Groton Generation Station near Groton, South Dakota; Crow Lake Wind Project near White Lake, South Dakota; Wisdom Unit 2 at Spencer, Iowa; and the Culbertson Generation Station near Culbertson, Montana.

Basin Electric purchases all or portions of the output from Waste Heat Recovery Units located near St. Anthony, North Dakota; Zeeland, North Dakota; Killdeer, North Dakota and three other Heat Recovery Units located in South Dakota; one in Montana; and one in Minnesota; North Dakota 1 Wind Energy Center near Edgeley and Kulm, North Dakota; the Wilton Wind Energy Center near Wilton, North Dakota; the Baldwin Wind Project near Baldwin, North Dakota; the South Dakota Wind Energy Center near Highmore, South Dakota; the Day County Wind Farm near Groton, South Dakota; the Pipestone, Minnesota School District Wind Turbine; a portion of Unit #4 of the George Neal Station near Salix, Iowa; the City of Madison, South Dakota Diesel Generators; Walter Scott Energy Center Units 3&4 near Council Bluffs, IA; Duane Arnold Energy Center near Palo, Iowa; Wisdom Station Units 1&2 near Spencer, Iowa; Spencer Combustion Turbine, Spencer, Iowa; Estherville, Iowa Diesel Generation; Pocahontas, Iowa Diesel Generation; Webster City, Iowa Combustion Turbine; and various wind facilities near Ayrshire, Iowa; Duncan/Klemme County, Iowa; Lakota, Iowa; and Superior, Iowa.

The most recent Energy Information Administration (EIA) Form No. 923 for the Antelope Valley Station and the Leland Olds Station are included as Exhibit 1.

SECTION B: ENERGY CONVERSION FACILITIES UNDER CONSTRUCTION

Basin Electric is developing the Deer Creek Station (300 MW) combined-cycle natural gas facility, located near White, SD. The commercial operation date is August of 2012; construction began the summer of 2010.

SECTION C: PROPOSED ENERGY CONVERSION FACILITIES ON WHICH CONSTRUCTION IS INTENDED WITHIN THE ENSUING FIVE YEARS

Basin Electric is developing a 45MW natural gas fired combustion turbine located near Williston, North Dakota. This project is named "Pioneer Generation Station" and the projected in-service date is the spring of 2013. Basin Electric is also developing a 45 MW natural gas fired combustion turbine located near Watford City, North Dakota. This project is named "Lonesome Creek Station" and the projected in-service date is the spring of 2013. Both the Pioneer Generation Station and the Lonesome Creek Station may accommodate future generation expansion possibilities. Basin Electric is continuing to investigate the need for additional generation in western North Dakota to meet the increasing needs of our membership.

SECTION D: PROPOSED ENERGY CONVERSION FACILITIES DURING THE NEXT TEN-YEAR TIME PERIOD

Basin Electric is evaluating the development of new generating resources (coal, gas, and wind) in the Dakotas to meet Basin Electric's forecasted load growth.

SECTION E: EXISTING TRANSMISSION FACILITIES (ELECTRIC)

Basin Electric's transmission and related substation facilities in North Dakota and their associated commercial dates are listed in the following table:

a. Transmission Lines

LINES - BY VOLTAGE	COMMERCIAL IN-SERVICE DATE
69 kV Lines	
Leland Olds - Basin Electric Sub	01/09/66
115 kV Lines	
Basin Electric Sub - Stanton Tap	01/09/66
Logan-Kenmare Line	04/01/79
Logan-Mallard Line	04/01/79
Charlie Creek-Squaw Gap	12/31/82

Squaw Gap-Richland	12/31/82

230 kV Lines

Leland Olds #1-Washburn Double Circuit	01/09/66
Leland Olds-Logan Line	03/31/80
Leland Olds #2 - Basin Electric Sub	12/15/75
Logan-Tioga	05/01/82
Tioga-Canadian Border (Estevan)	05/01/82
Belfield-Rhame	04/07/10
Williston-Tioga	01/10/11

345 kV Lines

Leland Olds-Groton-Watertown	12/15/75
Leland Olds-Ft. Thompson (SD) Line	12/15/75
Leland Olds-AVS North Line	11/30/83
Leland Olds-AVS South Line	07/01/84
Antelope Valley Station-Charlie Creek	11/30/83

500 kV Lines

Antelope Valley Station-Huron, SD (345 kV operation)	07/01/84

b. Substations

115 kV Wm. J. Neal Station Switchyard	04/01/52
230 kV Leland Olds Switchyard	01/09/66
230 kV Washburn, ND Switchyard	01/09/66
115 kV Stanton Tap Structure	01/09/66
230/115/69 kV BEPC Substation	01/09/66
345/230 kV Leland Olds Switchyard Addition	12/15/75
230/115 kV Dickinson, ND Substation	12/15/75
230/115 kV Logan Substation	04/01/79
345/115 kV Charlie Creek Substation	11/30/83
345 kV Antelope Valley Station Switchyard	11/30/83
230/115 kV Neset Substation	10/07/09
230 kV Rhame Substation	04/07/10

c. Basin Electric does not anticipate retiring any of its existing transmission facilities within the next ten (10) years.

SECTION F: EXISTING TRANSMISSION FACILITIES (PIPELINES)

Pipeline transmission facilities utilized by Basin Electric are water supply lines to the Leland Olds Station, Antelope Valley Station, and a 12 mile long natural gas fuel supply pipeline associated with the Groton Generation Station. The Leland Olds water line is approximately one-quarter mile in length and is located on plant site property owned by Basin Electric.

The water supply line for the Antelope Valley Station is a forty-two inch diameter steel-lined concrete pipe of approximately nine miles in length. The line runs directly north from the plant site to an intake structure and pumping station located on Lake Sakakawea. This line was designed and constructed as a joint use facility for Basin Electric and the adjacent Great Plains Synfuels Plant. The State of North Dakota's southwest water pipeline uses the same intake structure and pumping station as the Antelope Valley Station pipeline. The Basin Electric line was designed to have a maximum operating pressure of 160 PSI gauge and a flow rate of 30,000 GPM. The pipeline was constructed, with a minimum earth cover of 84 inches. The pipeline was placed in-service in 1984. A new parallel pipeline was installed in 2006, because of recurring failures of the existing line. The new line is steel pipe with the same design parameters. The old line will be maintained as a back-up facility. None of Basin Electric's pipeline facilities are projected for retirement within the next ten-year period.

SECTION G: PROPOSED TRANSMISSION FACILITIES ON WHICH CONSTRUCTION IS INTENDED WITHIN THE ENSUING FIVE YEARS (ELECTRIC)

Basin Electric is developing the Antelope Valley-Neset 345kV Transmission Line Project. The entire project will consist of constructing approximately 190 miles of new single circuit 345kV and double circuit 345/115kV transmission lines, the construction of two new substations, modifications to three existing substations and a 345kV switchyard, river crossings, temporary construction staging sites and other facilities. This project should be in-service by the end of 2015.

Basin Electric is also developing the Blaisdell-Berthold 115kV Transmission Line Project. This project will be 15 miles in length and should be in-service by the end of 2013.

Transmission studies are underway to analyze any other required transmission improvements to accommodate network load growth. Results of these studies may indicate the need for additional load serving transmission facilities.

SECTION H: PROPOSED TRANSMISSION FACILITIES ON WHICH CONSTRUCTION IS INTENDED WITHIN THE ENSUING FIVE YEARS (PIPELINE)

Basin is constructing a 14-mile long natural gas pipeline in South Dakota to supply gas to the Deer Creek Station described in Section B.

SECTION I: PROPOSED TRANSMISSION FACILITIES DURING THE NEXT TEN-YEAR TIME PERIOD (ELECTRIC AND PIPELINE)

Results of the resource development of new generating resources (refer to section D) will identify transmission improvements necessary to support the transmission service required by the new resources. Transmission studies are underway to analyze the required transmission improvements to accommodate network load growth. Results of these studies may indicate the need for additional load serving transmission facilities.

SECTION J: REGIONAL COORDINATION

Mid-West Electric Consumers Association

Basin Electric Power Cooperative is a member of the Mid-West Electric Consumers Association (Mid-West). Mid-West, which was founded in 1958, is a regional coalition of consumer-owned electric utilities that purchase power from the federal multi-purpose projects in the Missouri River Basin. Mid-West's Water & Power Marketing Committee meets throughout the year to discuss and review planned additions of Mid-West member utilities.

Mid-Continent Area Power Pool

Basin Electric is a member of the Mid-Continent Area Power Pool (MAPP). The Mid-Continent Area Power Pool (MAPP) is an association of electric utilities and other electric industry participants operating in all or parts of the following states and provinces: Iowa, Minnesota, Montana, Nebraska, North Dakota, South Dakota, and Manitoba. The MAPP organization has three primary functions: regional transmission planning, reliability planning and coordination, and transmission tariff services coordination. These functions support the provision of reliable, efficient, and economical power in the upper Midwest. Basin Electric participates on various committees and work groups as a function of the Mid-Continent Area Power Pool.

The Transmission Planning Committee (TPC), which coordinates MAPP's ten-year plan, has formed the MAPP Sub-Regional Planning Group, whose primary purpose is to perform coordinated transmission planning. The TPC also helps to coordinate activities related to MAPP transmission providers FERC order 890 and order 1000 efforts.

The MAPP Sub-Regional Planning Group includes utilities in the North and South Dakota area. In compliance with NERC planning standards, the group is required to

develop a coordinated ten-year plan for MAPP every two years for their region. This ten-year plan evaluates the adequacy of existing interconnected systems to support load growth and provide an indication of the ability of the system to meet regional reliability criteria.

Basin Electric also participates on the Design Review Subcommittee which ensures that long term reliability of the MAPP system is not adversely affected by changes to generation and transmission facilities.

Coordination with Area Utilities

Western Area Power Administration

Basin Electric coordinates regional power supplies with the Western Area Power Administration. An example is the Miles City, Montana DC converter station. The station was built by the Western Area Power Administration (WAPA) to transfer electric power across the east/west transmission separation. Basin Electric has financed 40% of the cost of the station and contracted with WAPA for 40% of the capacity of the 200 MW station. This station enables Basin Electric to serve Central Montana Electric Power Cooperative, a Class A member with electrical loads primarily located west of the east-west separation.

Montana-Dakota Utilities Co.

Member cooperatives of Basin Electric have a common service area in the western half of North Dakota with Montana-Dakota Utilities Co. (MDU). To avoid duplication of transmission facilities, an agreement was entered into on January 1, 1972, providing for joint use and construction of transmission facilities. This agreement provides for studies to be performed every two years to determine what additional transmission will be required to meet area load growth. This agreement calls for the sharing of facilities on the basis of each utility's respective load projections.

The Tioga-Saskatchewan 230 kV line constructed by Basin Electric and Saskatchewan Power Corporation allows the purchase and sale of power among regional utilities. This line was reviewed with MDU and routed so that it could be tapped for future use by MDU and the member systems of Basin Electric. A result of this review was the Tioga 230/115 kV substation constructed by MDU and shared by Basin Electric.

The Miles City-Hettinger-New Underwood, SD, 230 kV line is another example of joint planning. This line was jointly planned and constructed with WAPA, MDU and Basin Electric. Basin Electric and MDU each have 25% capacity rights and WAPA owns and has capacity rights to 50% of the line.

Integrated System Transmission Tariff

Basin Electric Power Cooperative, WAPA and Heartland Consumers Power District have combined their transmission facilities to create the Integrated System (IS) transmission tariff. This tariff was created to facilitate the use of the transmission

facilities of Basin Electric Power Cooperative, WAPA and Heartland Consumers Power District by other utilities required under FERC Order 888.

SECTION K: ENVIRONMENTAL INFORMATION

The primary obligation of Basin Electric is to provide an adequate wholesale supply of dependable, low-cost electric power to its member systems, consistent with the public interest. In conjunction with this, Basin Electric endeavors to maximize the socio-economic benefits associated with electrical generation and transmission projects and to minimize negative impacts associated with these projects. This is particularly true with respect to protecting the agricultural lifestyle and productivity of this region.

The Cooperative remains committed to preserving and enhancing the ecological balance of this region for the benefit of future generations. It is the policy of Basin Electric that environmental impacts be monitored and steps taken to mitigate and alleviate adverse effects. Basin Electric has instituted a variety of programs designed to maximize the most efficient use of energy and to benefit the human, agricultural, and biological environments.

Projects proposed by Basin Electric adhere to the requirements of the Rural Utilities Service Environmental Policies and Procedures which describe the procedures for compliance with the provisions of the National Environmental Policy Act (NEPA). Through the NEPA process, Basin Electric encourages state, federal and public participation in proposed projects so that once potential impact issues are identified appropriate mitigation measures can be formulated with the assistance of the participants to minimize potential impacts. An Environmental Assessment is developed which includes a comprehensive discussion and evaluation of environmental issues and serves as a baseline document for subsequent environmental regulatory permits and a federal Environmental Impact Statement when required. The goal of this process is to select a facility location that best minimizes environmental, cultural and socio-economic impacts and engineering and construction costs.

Basin Electric adheres to the appropriate North Dakota statutes regulating industrial development projects such as electrical generating facilities and high voltage transmission lines and substations. In addition, it is Basin Electric's practice to inform affected state and federal agencies when prospective projects are identified to solicit their input early in the planning process.

Basin Electric utilizes a socio-economic impact management program to assist communities in addressing population growth associated with the construction of energy conversion facilities. Basin Electric follows an open-planning process to determine the specific negative and positive impacts that may develop in an area, and works closely with the local citizens and public officials on key issues. Once issues are defined, strategies are recommended to alleviate the adverse conditions. Basin Electric further provides public officials with the technical assistance to secure financing for public services and facilities needed to alleviate negative impacts.

SECTION L: PROJECTED DEMAND FOR SERVICES

Exhibit 2 represents Basin Electric's sale to its Class A members. This exhibit represents Basin Electric's supplemental power supply responsibilities to its members. As a supplemental power supplier, Basin Electric is responsible for providing the members requirements in excess of the fixed amount of power they receive from WAPA and other sources.

An econometric based load forecast was completed in early 2011with an annual update completed in early 2012. The econometric forecasting system in the load forecast is a bottom up process that begins by developing econometric equations and forecasts for each distribution cooperative. The total system consists of approximately 350 forecasting equations and over 700 explanatory variables. Annual and monthly forecasts of energy and demand are conducted for a 15-year period. The distribution cooperative forecasts are combined to obtain the generation and transmission cooperative forecasts (G&T's). The G&T's power requirements are then separated into various power supply responsibilities. The Basin Electric components are combined to obtain the Basin Electric total power supply responsibility.

The modeling and forecasting is performed at Basin Electric. Throughout the modeling and forecasting process there is constant communication and review by member systems and the Rural Utilities Service (RUS) in Washington, D.C. The RUS is responsible to review and approve close to 1,000 distribution cooperative forecasts as well as large G&T systems forecasts such as Basin Electric. The RUS insures that state of the art methods and technologies are being used to produce short term and long-term forecasts. Historical energy data is combined with external data obtained from government and private sector sources as well as membership to form econometric forecasting equations. External projections of explanatory economic and demographic variables used in the forecasting process are obtained from the Food and Agricultural Policy Research Institute at the University of Missouri-Columbia, MO.; Woods & Poole Economics, Inc.; and the Department of Energy, Washington, D.C.; as well as others.

Basin Electric's service area is electrically divided into western and eastern systems. These systems are separated by the east-west ties, which are boundaries that separate two major electrical regions of the United States. This boundary essentially runs south from Fort Peck, MT, approximately following the South Dakota-Wyoming, Nebraska-Wyoming, and Colorado-Kansas borders. As a result of this, Basin Electric must supply generating capacity and energy on both sides of the ties to serve its member-load requirements.

The resources available to Basin Electric to serve its members' east-side requirements are as follows:

1. Leland Olds Station: Leland Olds Unit 1 was placed in-service on January 9, 1966 and is a base-load thermal unit located near Stanton, ND with a net capacity of 222 MW. Leland Olds Unit 2 was placed in-service on December 15, 1975 with a net capacity of 447 MW. Basin Electric has committed to install emission control equipment at the Leland Olds Station which requires an increase to the station

service. This equipment is anticipated to be installed in the fall of 2012 for Unit 2 and the spring of 2013 for Unit 1.

2. WAPA Peaking Capacity: In 1968 Basin Electric executed a long-term contract with the federal government for USBR (now WAPA) hydro peaking from the dams in the Missouri River Basin. This contract currently provides Basin Electric with 268.2 MW of winter peaking capacity at load, whereas an at-plant value includes losses on the Integrated System (IS).

3. Spirit Mound Station: Basin Electric placed in service two 60 MW (net) nameplate oil-fired combustion turbines on June 30, 1978. The combined winter rating of the two units is 120 MW (net) and the summer rating is 100 MW (net). The capacity is intended to be used primarily as reserves or replacement during initial outages of base-load units or during peak load periods when existing base-load units cannot meet the demand. The Spirit Mound Station is located near Vermillion, SD.

4. Laramie River Station: Basin Electric, together with five other consumer-owned power supply entities, began construction of the Laramie River Station near Wheatland in southeast Wyoming in July, 1976. The station's three units became fully operational on November 1, 1982, with Unit 1 at a net capacity of 570 MW; Unit 2 at a net capacity of 570 MW; and Unit 3 at a net capacity of 570 MW. The current rating of the units is due to turbine upgrades that occurred in 2007, 2008 and 2009. Basin Electric, as Project Manager and Operating Agent for the Missouri Basin Power Project, was assigned overall responsibility for the design, construction and operation of the power plant and related transmission. Units 2 and 3 of the Laramie River Station are electrically connected to the western system; Unit 1 is electrically connected to the eastern system. The amount of power Basin Electric receives from the eastern unit is 48 MW (net).

5. Antelope Valley Station: Basin Electric operates two 450 MW (net) thermal-generating units near Beulah, ND. Approximately 110+ MW of electric power for the Dakota Gasification Company Synfuels Plant facilities are supplied by the Antelope Valley Station. Unit 1 began commercial operation on July 1, 1984 and Unit 2 began partial commercial operation on June 1, 1986.

6. Neal IV: Basin Electric and Northwest Iowa Power Cooperative (NIPCO), one of Basin Electric's member cooperative, negotiated a power supply contract which provides that NIPCO will sell to Basin Electric NIPCO's 31 MW of uncommitted capacity and associated energy from Unit No. 4 of the George Neal Generating Station (Neal IV). In return NIPCO entered into a wholesale power contract with Basin Electric whereby Basin Electric will sell and deliver to NIPCO all of NIPCO's capacity and energy requirements in excess of the power and energy available to NIPCO from the Western Area Power Administration.

   Basin Electric and Corn Belt Power Cooperative (Corn Belt), one of Basin Electric's member cooperatives, negotiated a power supply contract which provides that Corn Belt will sell to Basin Electric Corn Belt's 73 MW of uncommitted capacity and associated energy from Unit No. 4 of the George Neal Generating Station (Neal IV). In return, Corn Belt entered into a wholesale power contract with Basin Electric

whereby Basin Electric will sell and deliver to Corn Belt all of Corn Belt's capacity and energy requirements in excess of the power and energy available to Corn Belt from the Western Area Power Administration.

7. Chamberlain Wind Project: Basin Electric, in partnership with East River Power Cooperative, has constructed a wind energy project near Chamberlain, South Dakota. The 2.6 megawatt capacity project was placed into commercial service in January 2002. The energy is delivered to members as part of Basin Electric's overall power supply.

8. Minot Wind Project: Basin Electric, in partnership with Central Power Electric Cooperative, has constructed a wind energy project 14 miles south of Minot, North Dakota. The 2.6 megawatt capacity wind project was placed into commercial service in February 2002. Three additional turbines were added in December 2009 for a total output of 7.1 megawatts. The energy is delivered to members as part of Basin Electric's overall power supply.

9. PrairieWinds 1: Basin Electric, in partnership with PrairieWinds ND 1 Inc., has constructed a wind energy project of 77 turbines near Minot, North Dakota. The 115.5 MW capacity wind project was placed into commercial service in December, 2009.

10. Crow Lake Wind Project: Basin Electric, in partnership with Prairie Winds SD1 Inc., South Dakota Wind Partners and Mitchell Technical Institute, has constructed a wind energy project of 108 turbines near White Lake, South Dakota. The 162 MW capacity wind project was placed into commercial service. Basin Electric's subsidiary, Prairie Winds SD1, owns 100 turbines or 150 MW. Basin Electric has a purchase power contract for all 108 turbines or 162 MW from the Crow Lake Wind Project.

11. Walter Scott 3 and 4: Basin Electric and Corn Belt Power Cooperative (Corn Belt), one of Basin Electric's member cooperatives, negotiated a power supply contract which provides that Corn Belt will sell to Basin Electric Corn Belt's 26 MW of uncommitted capacity and associated energy from Unit No. 3 and 45 MW of uncommitted capacity and associated energy from Unit No. 4 of the Walter Scott Energy Center. In return, Corn Belt entered into a wholesale power contract with Basin Electric whereby Basin Electric will sell and deliver to Corn Belt all of Corn Belt's capacity and energy requirements in excess of the power and energy available to Corn Belt from the Western Area Power Administration.

12. Duane Arnold Energy Center: Basin Electric and Corn Belt Power Cooperative (Corn Belt), one of Basin Electric's member cooperatives, negotiated with a power supply contract which provides that Corn Belt will sell to Basin Electric Corn Belt's 62 MW of uncommitted capacity and associated energy from the Duane Arnold Energy Center. In return, Corn Belt entered into a wholesale power contract with Basin Electric whereby Basin Electric will sell and deliver to Corn Belt all of Corn Belt's capacity and energy requirements in excess of the power and energy available to Corn Belt from the Western Area Power Administration.

13. Wisdom Unit 1: Basin Electric and Corn Belt Power Cooperative (Corn Belt), one of Basin Electric's member cooperatives, negotiated a power supply contract which provides that Corn Belt will sell to Basin Electric Corn Belt's 38 MW of uncommitted capacity and associated energy from the Earl F. Wisdom Unit 1. In return, Corn Belt entered into a wholesale power contract with Basin Electric whereby Basin Electric will sell and deliver to Corn Belt all of Corn Belt's capacity and energy requirements in excess of the power and energy available to Corn Belt from the Western Area Power Administration.

14. Wisdom Unit 2: Basin Electric partnered with Corn Belt Power Cooperative to build the 80 MW natural gas peaking unit near Spencer, Iowa. Basin Electric owns one half of the unit, which was placed in service in April 2004. Basin Electric purchases 87.5 % of Corn Belt's owned half in response to Corn Belt entering into a Wholesale Power Contract.

15. Groton Generation Station: Basin Electric commissioned Groton Unit 1 in 2006 and Unit 2 in 2008. These units provide peaking power. They each have winter ratings of 100 MW.

16. Culbertson Generation Station: Basin Electric commissioned Culbertson Unit 1 in 2010. The unit provides peaking power. The unit has a winter rating of 100 MW.

17. Other Short-Term Resources: Basin Electric has also entered into a number of short-term purchase agreements to meet contractual power supply obligations. Due to the relatively short duration of these arrangements no specifics are provided.

18. Long-Term Resource: Basin Electric has entered into a long-term purchase agreement with NextEra Energy Resources to meet contractual power supply obligations. A 40 megawatt wind energy project is located just west of Edgeley, ND; two 49.5 MW wind energy projects are located near Wilton, ND; a 40 megawatt wind energy project is located near Highmore, SD; a 99 MW wind energy project is located near Groton, SD; and a 100 MW wind energy project is located near Baldwin, ND. Basin Electric also entered into a long-term purchase agreement with the City of Madison which provides 10 MW of peaking power from a diesel unit at Madison, SD. Basin Electric has a purchase power agreement with Ormat Industries for eight 5.5 MW waste heat recovery units. Three sites are in North Dakota near St. Anthony, Manning, and Zeeland. Three sites are in South Dakota, one in Montana and one in Minnesota. Basin Electric also purchases the output from the following generating facilities from its member cooperative Corn Belt, 25 MW from the Webster City, IA combustion turbine; 13 MW from the diesel generators at Estherville, IA; 3.8 MW from the diesel generators at Pocahontas, IA; 10 MW from the combustion turbine located at Spencer, IA; and from the following wind generating projects, 7.3 MW of Hancock County, 16.8 MW of Crosswinds, 10.5 MW from Lakota and 10.5 MW from Superior, all located within Iowa. Basin Electric also has long term purchases from Minnesota Power for 100 MW and 30 MW from Municipal Energy Agency of Nebraska.

19. Future Power Supply: For discussion of future power supply, please refer to Section B (Energy Conversion Facilities Under Construction) and Section D (Proposed Energy Conversion Facilities During the Next Ten-Year Time Period).

The resources available to Basin Electric to serve its members' west-side requirements are as follows:

1. Laramie River Station: The Laramie River Station capacity that Basin Electric will receive from the two west-side units is 675 MW (net).

2. Miles City DC Tie: Basin Electric and the Western Area Power Administration have jointly constructed a 200 MW back-to-back, AC-DC-AC tie built at Miles City, MT. This tie, which provides a 40% capacity entitlement, enables Basin Electric to serve Central Montana Electric Power Cooperative Inc., a Class A member with electrical loads located primarily west of the east-west ties, using capacity from east-side resources such as Antelope Valley Station.

3. Rapid City DC Tie: Basin Electric and Black Hills Power, Inc. have jointly constructed a 200 MW asynchronous tie at Rapid City, SD. This tie enables Basin Electric to serve new coalbed methane load growth in northeastern Wyoming located west of the east-west ties, using capacity and/or energy from east side resources such as Antelope Valley Station. The Basin Electric ownership percentage is 65% and the Black Hills Power, Inc. ownership percentage is 35%.

4. Wyoming Distributed Generation: The Wyoming Distributed Generation consists of 9 units located at 3 sites; Arvada, Hartzog and Barber Creek. These units are natural gas fired units with a total net output of 45 MW summer and 54 MW winter.

5. Dry Fork Station: The Dry Fork Station is a 390 MW (net) coal fired power plant located 10 miles north of Gillette, Wyoming. Basin Electric owns 92.9% of the station.

The load values contained in Exhibit 2 were obtained from the econometric based load forecast. These loads have been adjusted to an at-generator system coincident basis by allowing for reserves, on-peak losses and system diversity as outlined in Exhibit 3.

1. Basin Electric has no concentrated load centers due to the regional and rural nature of the total load. The fuel sources and transportation facilities for existing and future plants are as follows:

Plant	Fuel Source	Transportation
Leland Olds Station	ND Lignite/Wyoming (PRB) Coal	Rail
Spirit Mound Station	Oil	Pipeline
Laramie River Station	Wyoming (PRB) Coal	Rail
Antelope Valley Station	ND Lignite/Wyoming (PRB) Coal	Mine Mouth/Rail
Minot Wind Project	Wind	N/A
Wyoming Distributed Generation	Natural Gas	Pipeline

Wisdom Unit 2	Natural Gas/Fuel Oil	Pipeline
Chamberlain Wind Project	Wind	N/A
Groton Generation Station	Natural Gas	Pipeline
PrairieWinds 1 Wind Project	Wind	N/A
Crow Lake Wind Project	Wind	N/A
Culbertson Generation Station	Natural Gas	Pipeline
Deer Creek Station	Natural Gas	Pipeline
Dry Fork Station	Wyoming (PRB) Coal	Mine Mouth

2. Pursuant to federal and state laws, Basin Electric will examine all alternatives capable of producing an adequate and reliable source of energy for its member cooperatives.

   Specific alternatives selected will be evaluated considering environmental, engineering and economic factors. Additional facilities, transmission and generation will be designed and operated in accordance with state and federal standards.

EXHIBIT 1

U.S. Department of Energy Form EIA-923
(distributed only to the Public Services Commission)

EXHIBIT 2

Summer/Winter Loads

Basin Electric Member Loads by State

Note: Historical 1995-2011 and Forecasted 2012-2025

SUMMER Peak Demand (MW)

	ND	%	SD	%	MN	%	IA	%	NE	%	MT	%	CO	%	WY	%	BEPC TOTAL
1995	223.9	22.3%	235.9	23.5%	38.9	3.9%	71.6	7.1%	186.2	18.5%	21.2	2.1%	77.9	7.8%	148.9	14.8%	1004.5
1996	222.1	22.6%	220.2	22.4%	38.4	3.9%	67.0	6.8%	170.2	17.3%	27.8	2.8%	78.2	7.9%	160.7	16.3%	984.7
1997	244.0	22.6%	239.0	22.2%	41.3	3.8%	77.6	7.2%	195.5	18.1%	26.8	2.5%	82.3	7.6%	171.6	15.9%	1078.1
1998	248.7	21.8%	273.0	24.0%	47.1	4.1%	83.2	7.3%	211.3	18.6%	28.1	2.5%	84.3	7.4%	162.8	14.3%	1138.4
1999	267.9	22.4%	288.5	24.2%	52.5	4.4%	102.2	8.6%	197.4	16.5%	28.3	2.4%	83.9	7.0%	173.8	14.6%	1194.5
2000	292.6	23.0%	301.7	23.7%	53.9	4.2%	98.7	7.8%	214.9	16.9%	28.9	2.3%	82.4	6.5%	199.9	15.7%	1273.0
2001	306.5	22.2%	342.5	24.8%	58.0	4.2%	116.0	8.4%	227.3	16.5%	30.3	2.2%	81.9	5.9%	217.9	15.8%	1380.4
2002	315.3	21.3%	351.9	23.8%	57.7	3.9%	127.1	8.6%	253.5	17.1%	43.9	3.0%	94.6	6.4%	235.5	15.9%	1479.6
2003	353.0	22.9%	345.5	22.4%	57.8	3.8%	121.4	7.9%	239.1	15.5%	55.9	3.6%	114.0	7.4%	253.9	16.5%	1540.6
2004	328.8	21.2%	353.9	22.8%	55.4	3.6%	119.0	7.7%	233.4	15.0%	61.8	4.0%	130.1	8.4%	271.3	17.5%	1553.6
2005	356.6	20.7%	400.1	23.2%	62.0	3.6%	131.1	7.6%	269.7	15.7%	74.2	4.3%	131.6	7.6%	296.4	17.2%	1721.6
2006	400.0	20.5%	440.4	22.6%	71.4	3.7%	187.9	9.7%	272.9	14.0%	82.0	4.2%	134.3	6.9%	358.0	18.4%	1946.9
2007	451.9	21.9%	460.8	22.3%	91.6	4.4%	186.1	9.0%	261.6	12.7%	86.4	4.2%	135.2	6.6%	388.9	18.9%	2062.5
2008	464.6	22.5%	420.7	20.4%	87.5	4.2%	177.0	8.6%	270.1	13.1%	73.8	3.6%	142.2	6.9%	426.4	20.7%	2062.3
2009	448.3	21.4%	437.5	20.9%	101.6	4.9%	201.0	9.6%	231.5	11.1%	64.8	3.1%	145.4	7.0%	400.1	19.1%	2090.1
2010	509.1	20.5%	472.3	19.0%	181.0	7.3%	459.1	18.5%	237.9	9.6%	69.6	2.8%	145.4	5.9%	407.1	16.4%	2481.5
2011	517.1	19.8%	545.8	20.9%	173.2	6.6%	459.1	17.6%	280.3	10.8%	95.6	3.7%	140.7	5.4%	395.1	15.2%	2606.9
2012	683.3	24.2%	514.6	18.2%	161.4	5.7%	470.7	16.7%	288.9	10.2%	108.4	3.8%	191.0	6.8%	408.3	14.4%	2826.8
2013	862.2	28.6%	516.7	17.1%	162.4	5.4%	468.5	15.5%	294.4	9.8%	117.7	3.9%	191.0	6.3%	406.1	13.5%	3019.2
2014	915.4	29.3%	524.9	16.8%	168.0	5.4%	473.6	15.2%	299.7	9.6%	142.7	4.6%	191.0	6.1%	403.7	12.9%	3119.0
2015	973.4	30.3%	533.9	16.6%	175.4	5.5%	477.2	14.9%	303.0	9.4%	152.0	4.7%	191.0	5.9%	404.1	12.6%	3210.1
2016	1026.5	29.9%	626.0	18.3%	184.2	5.4%	481.0	14.0%	305.8	8.9%	212.3	6.2%	191.0	5.6%	402.9	11.7%	3429.7
2017	1100.3	31.2%	636.5	18.0%	193.0	5.5%	484.3	13.7%	308.5	8.7%	214.3	6.1%	191.0	5.4%	399.0	11.3%	3526.9
2018	1149.4	31.9%	647.2	18.0%	202.3	5.6%	487.5	13.5%	311.3	8.6%	216.5	6.0%	191.0	5.3%	396.6	11.0%	3601.7
2019	1212.0	32.8%	658.4	17.8%	212.2	5.7%	490.7	13.3%	313.6	8.5%	218.7	5.9%	191.0	5.2%	394.2	10.7%	3690.9
2020	1270.4	33.7%	668.1	17.7%	220.4	5.8%	493.3	13.1%	313.3	8.3%	220.4	5.8%	191.0	5.1%	393.1	10.4%	3770.0
2021	1315.9	34.3%	678.7	17.7%	230.0	6.0%	496.2	12.9%	313.4	8.2%	222.5	5.8%	191.0	5.0%	392.5	10.2%	3840.3
2022	1360.5	34.8%	689.9	17.6%	239.6	6.1%	499.5	12.8%	314.2	8.0%	224.8	5.7%	191.0	4.9%	391.9	10.0%	3911.4
2023	1404.9	35.3%	701.1	17.6%	249.3	6.3%	502.9	12.6%	314.6	7.9%	226.9	5.7%	191.0	4.8%	388.6	9.8%	3979.4
2024	1447.6	35.8%	712.8	17.6%	259.4	6.4%	506.4	12.5%	318.0	7.9%	229.3	5.7%	191.0	4.7%	382.3	9.4%	4046.7
2025	1488.3	36.2%	724.6	17.6%	269.5	6.6%	510.1	12.4%	319.1	7.8%	231.5	5.6%	191.0	4.6%	378.9	9.2%	4112.9

WINTER Peak Demand (MW)

	ND	%	SD	%	MN	%	IA	%	NE	%	MT	%	CO	%	WY	%	BEPC TOTAL
95/96	325.8	29.4%	309.0	27.9%	51.2	4.6%	88.9	8.0%	33.3	3.0%	31.6	2.9%	77.4	7.0%	189.9	17.2%	1107.0
96/97	334.5	29.3%	302.7	26.6%	47.9	4.2%	98.5	8.6%	35.7	3.1%	30.2	2.6%	79.8	7.0%	210.7	18.5%	1140.0
97/98	324.0	30.5%	263.3	24.8%	42.2	4.0%	77.5	7.3%	35.8	3.4%	29.3	2.8%	83.5	7.9%	207.9	19.6%	1063.4
98/99	331.3	29.2%	291.8	25.8%	47.8	4.2%	109.2	9.6%	37.0	3.3%	30.4	2.7%	84.3	7.4%	201.2	17.8%	1133.1
99/00	312.3	28.8%	269.3	24.8%	47.9	4.4%	102.3	9.4%	31.0	2.9%	28.0	2.6%	83.9	7.7%	209.0	19.3%	1083.8
00/01	342.1	27.4%	328.0	26.2%	57.4	4.6%	124.6	10.0%	42.5	3.4%	33.6	2.7%	83.2	6.7%	238.7	19.1%	1250.0
01/02	312.5	26.2%	300.4	25.2%	47.1	3.9%	108.4	9.1%	37.4	3.1%	34.9	2.9%	82.4	6.9%	270.3	22.6%	1193.4
02/03	376.7	27.7%	342.3	25.1%	54.0	4.0%	127.8	9.4%	35.7	2.6%	55.0	4.0%	103.1	7.6%	267.5	19.6%	1362.2
03/04	416.9	27.5%	393.8	25.9%	59.7	3.9%	134.2	8.8%	35.6	2.3%	62.4	4.1%	122.5	8.1%	293.2	19.3%	1518.4
04/05	437.9	27.4%	416.6	26.1%	62.7	3.9%	138.7	8.7%	43.5	2.7%	64.0	4.0%	121.2	7.6%	314.4	19.7%	1598.9
05/06	462.6	26.8%	414.7	24.0%	65.8	3.8%	186.6	10.8%	48.4	2.8%	72.2	4.2%	120.8	7.0%	353.4	20.5%	1724.6
06/07	494.6	25.4%	484.4	24.9%	111.0	5.7%	211.5	10.9%	50.0	2.6%	70.6	3.6%	121.8	6.3%	402.6	20.7%	1946.4
07/08	562.7	26.3%	524.3	24.5%	113.3	5.3%	231.7	10.8%	50.0	2.3%	80.7	3.8%	123.5	5.8%	454.0	21.2%	2140.2
08/09	622.7	25.7%	633.9	26.2%	133.3	5.5%	276.1	11.4%	56.5	2.3%	78.3	3.2%	137.8	5.7%	481.0	19.9%	2419.5
09/10	627.3	23.5%	618.6	23.2%	169.0	6.3%	517.7	19.4%	58.8	2.2%	73.6	2.8%	137.2	5.1%	468.4	17.5%	2670.6
10/11	656.1	24.3%	618.8	22.9%	201.8	7.5%	466.9	17.3%	54.5	2.0%	78.0	2.9%	146.1	5.4%	475.5	17.6%	2697.8
11/12	779.8	26.5%	652.3	22.2%	226.8	7.7%	490.5	16.7%	53.5	1.8%	102.8	3.5%	185.9	6.3%	446.5	15.2%	2938.1
12/13	1000.2	31.6%	656.5	20.7%	226.4	7.1%	487.2	15.4%	53.7	1.7%	115.8	3.7%	185.9	5.9%	443.6	14.0%	3169.4
13/14	1057.6	32.5%	664.6	20.4%	231.2	7.1%	492.7	15.1%	53.8	1.7%	129.2	4.0%	185.9	5.7%	441.5	13.6%	3256.6
14/15	1131.5	33.5%	676.3	20.0%	238.1	7.0%	497.8	14.7%	54.4	1.6%	152.4	4.5%	185.9	5.5%	442.2	13.1%	3378.6
15/16	1196.6	34.5%	687.5	19.8%	246.4	7.1%	503.0	14.5%	55.1	1.6%	157.7	4.5%	185.9	5.4%	440.7	12.7%	3472.8
16/17	1283.2	34.4%	785.6	21.1%	254.7	6.8%	507.5	13.6%	55.7	1.5%	218.2	5.9%	185.9	5.0%	437.2	11.7%	3728.0
17/18	1343.2	35.2%	798.5	20.9%	263.6	6.9%	511.8	13.4%	56.2	1.5%	220.8	5.8%	185.9	4.9%	434.8	11.4%	3814.8
18/19	1416.9	36.2%	812.1	20.7%	273.1	7.0%	516.1	13.2%	56.8	1.5%	223.4	5.7%	185.9	4.7%	432.0	11.0%	3916.3
19/20	1485.7	37.0%	823.7	20.5%	280.7	7.0%	519.5	13.0%	57.4	1.4%	225.4	5.6%	185.9	4.6%	432.1	10.8%	4010.4
20/21	1541.2	37.6%	836.3	20.4%	289.8	7.1%	523.5	12.8%	57.7	1.4%	227.9	5.6%	185.9	4.5%	431.6	10.5%	4094.1
21/22	1595.9	38.2%	849.5	20.3%	299.1	7.2%	527.9	12.6%	58.1	1.4%	230.6	5.5%	185.9	4.4%	431.1	10.3%	4178.2
22/23	1650.3	38.7%	862.9	20.3%	308.4	7.2%	532.5	12.5%	58.6	1.4%	233.1	5.5%	185.9	4.4%	427.9	10.0%	4259.5
23/24	1702.5	39.3%	876.7	20.2%	318.1	7.3%	537.3	12.4%	59.2	1.4%	235.9	5.4%	185.9	4.3%	421.4	9.7%	4337.0
24/25	1752.1	39.7%	890.8	20.2%	327.9	7.4%	542.3	12.3%	59.7	1.4%	238.5	5.4%	185.9	4.2%	418.3	9.5%	4415.6

EXHIBIT 3

Eastern System Summer/Winter Load Resources

SUMMER SEASON

	Members' Load Projections	Contracted Sales to Others	Contingency* Losses, Diversity, and Reserves	Total Responsibility
2012	2,250	261	606	3,117
2013	2,444	245	660	3,350
2014	2,545	253	685	3,482
2015	2,632	230	706	3,568
2016	2,851	209	745	3,805
2017	2,951	208	790	3,949
2018	3,028	207	810	4,045
2019	3,118	206	835	4,159
2020	3,197	206	856	4,259
2021	3,267	205	875	4,348

WINTER SEASON

	Members' Load Projections	Contracted Sales to Others	Contingency* Losses, Diversity, and Reserves	Total Responsibility
2012/13	2,524	210	661	3,395
2013/14	2,612	216	685	3,513
2014/15	2,729	216	715	3,660
2015/16	2,823	191	736	3,750
2016/17	3,080	192	803	4,076
2017/18	3,168	192	826	4,186
2018/19	3,271	193	853	4,317
2019/20	3,364	193	877	4,434
2020/21	3,447	193	899	4,539
2021/22	3,530	193	921	4,644

*Contingency adjusts for peak conditions due to the load forecasted is based on a weather normalized pattern.

2012 Resources

Summer Season

	LOS	LRS	AVS	NEAL 4	WS	Wisdom 1	DAEC	SMS	Groton	Culbertson	Deer Creek	Pioneer	Lonesome Creek	Wisdom 2	Madison	Webster City	Estherville	Pocahontas	Spencer	Wind	Waste Heat	Purchases
2012	670	48	900	106	71	37	60	99	153	91	294	0	0	72	10	20.8	13	3.8	10	121	35.4	135.3
2013	670	48	900	106	71	37	60	99	153	91	294	40	40	72	10	20.8	13	3.8	10	121	35.4	135.3
2014	670	48	900	106	71	37	60	99	153	91	294	40	40	72	10	20.8	13	3.8	10	121	35.4	105.3
2015	670	48	900	106	71	37	60	99	153	91	294	40	40	72	10	20.8	13	3.8	10	121	35.4	105.3
2016	670	48	900	106	71	37	60	99	153	91	294	40	40	72	10	20.8	13	3.8	10	121	35.4	105.3
2017	670	48	900	106	71	37	60	99	153	91	294	40	40	72	10	20.8	13	3.8	10	121	35.4	105.3
2018	670	48	900	106	71	37	60	99	153	91	294	40	40	72	10	20.8	13	3.8	10	121	35.4	105.3
2019	670	48	900	106	71	37	60	99	153	91	294	40	40	72	10	20.8	13	3.8	10	121	35.4	105.3
2020	670	48	900	106	71	37	60	99	153	91	294	40	40	72	10	20.8	13	3.8	10	121	35.4	105.3
2021	670	48	900	106	71	37	60	99	153	91	294	40	40	72	10	20.8	13	3.8	10	121	35.4	105.3

Winter Season

	LOS	LRS	AVS	NEAL 4	WS	Wisdom 1	DAEC	SMS	Groton	Culbertson	Deer Creek	Pioneer	Lonesome Creek	Wisdom 2	Madison	Webster City	Estherville	Pocahontas	Spencer	Wind	Waste Heat	Purchases
2012/13	670	48	900	106	72	38	62	119	195	95	300	0	0	75	10	24.9	13	3.8	10	217.3	36.9	135.3
2013/14	670	48	900	106	72	38	62	119	195	95	300	40	40	75	10	24.9	13	3.8	10	217.3	36.9	135.3
2014/15	670	48	900	106	72	38	62	119	195	95	300	40	40	75	10	24.9	13	3.8	10	217.3	36.9	105.3
2015/16	670	48	900	106	72	38	62	119	195	95	300	40	40	75	10	24.9	13	3.8	10	217.3	36.9	105.3
2016/17	670	48	900	106	72	38	62	119	195	95	300	40	40	75	10	24.9	13	3.8	10	217.3	36.9	105.3
2017/18	670	48	900	106	72	38	62	119	195	95	300	40	40	75	10	24.9	13	3.8	10	217.3	36.9	105.3
2018/19	670	48	900	106	72	38	62	119	195	95	300	40	40	75	10	24.9	13	3.8	10	217.3	36.9	105.3
2019/20	670	48	900	106	72	38	62	119	195	95	300	40	40	75	10	24.9	13	3.8	10	217.3	36.9	105.3
2020/21	670	48	900	106	72	38	62	119	195	95	300	40	40	75	10	24.9	13	3.8	10	217.3	36.9	105.3
2021/22	670	48	900	106	72	38	62	119	195	95	300	40	40	75	10	24.9	13	3.8	10	217.3	36.9	105.3

U.S. Department of Energy
Energy Information Administration
Form EIA-923

EIA923 Power Plant Operations Report

Year: **2011** Plant: **6469** **Antelope Valley**

Form Approval
OMB No. 1905-0129
Approval Expires 12/31/2010

NOTICE: This report is mandatory under the Federal Energy Administration Act of 1974 (Public Law 93-275). Failure to comply may result in criminal fines, civil penalties and other sanctions as provided by law. For further information concerning sanctions and data protections see the provision on sanctions and the provision concerning confidentiality of information in the instructions. **Title 18 USC 1001 makes it a criminal offense for any person knowingly and willingly to make to any Agency or Department of the United States any false, fictitious, or fraudulent statements as to any matter within its jurisdiction.**

SCHEDULE 1. IDENTIFICATION

Survey Contact

Contact	Joseph Leingang	Submit By	300002472
Title	Director of Fuels	Submit Date	04-APR-12
Address	1717 E. Interstate Avenue	Accept By	
		Accept Date	
City/State/Zip	Bismarck ND 58503		
Email	jleingang@bepc.com	Phone (701) 557-5648	Fax (701) 557-5144

Supervisor of Contact Person for Survey

Contact	Terry Retterath		
Title	Industrial Engineer III		
Address	1717 E. Interstate Avenue		
City/State/Zip	Bismarck ND 58503		
Email	tlrat@bepc.com	Phone (701) 223-0441	Fax (701) 557-5144

Report For

Company Name	Basin Electric Power Coop		
Plant Name	Antelope Valley		
Plant ID	6469	Plant County	Mercer
Plant Address	Hwy 200		
Plant City	Beulah	Plant State	ND

Regulated	[X] Yes	[ ] No
CHP	[ ] Yes	[X] No
CHP Efficiency		

For contact detail go to http://www.eia.doe.gov/oss/forms.html#eia-923

SCHEDULE 6. NONUTILITY ANNUAL SOURCE AND DISPOSITION OF ELECTRICITY

(Instructions for SCHEDULE 6 are on page 13)

SCHEDULE 6 collects calendar year data (no monthly detail).
Annual data are due by March 30 following the reporting year.
Report all generation in **megawatthours (MWh)** rounded to a whole number.

(1) Gross Generation (Annual)

(2) Other Incoming Electricity

(3) Total Sources (1 + 2)

(4) Station Use

(5) Direct Use

(6) Total Facility Use (4 + 5)

(7) Retail Sales to Ultimate Customers

(8) Sales for Resale (MWh)

(9) Other Outgoing Electricity

(10) Total Disposition (6 + 7 + 8+ 9)

Total Sources must equal Total Disposition (3 = 10)

Plants that cannot separate Station Use and Direct Use may enter zero in Station Use and the sum of Station Use and Direct Use in the Direct Use field.

SCHEDULE 7. ANNUAL REVENUES FROM SALES FOR RESALE

(Instruction for SCHEDULE 7 are on page 14.)

SCHEDULE 7 is to be completed by respondents who entered a positive amount on SCHEDULE 6, Disposition of Electricity, Item 8, Sales for Resale. Annual data are due by March 30 following the reporting year.

Sales for Resale is energy supplied to other electric utilities, cooperatives, municipalities, Federal and State electric agencies, or other entities for resale to end-use consumers.

Annual Revenues from Sales for Resale (in thousand dollars)

SCHEDULE 8. ANNUAL ENVIRONMENTAL INFORMATION

SCHEDULE 8. PARTS A through F are filed annually and must be reported by steam-electric organic-fueled power plants with a total steam turbine capacity of 100 megawatts and above (only plants that reported boiler-level consumption on SCHEDULE 3. Part A.). All steam-electric organic-fueled power plants with a total steam turbine capacity of 10 megawatts and above are responsible for filing Schedule 8, Parts C, E, and F. Annual data are due by March 30 following the reporting year.

SCHEDULE 8. PART A. ANNUAL BYPRODUCT DISPOSITION

(Instructions for SCHEDULE 8 PART A are on page 14)

Enter the quantity of combustion byproducts for the year by type of disposal (to nearest 0.1 thousand tons). Report sales of steam in million Btu (MMBtu). If actual data are not available, provide an estimated value.

No Byproducts

Byproduct	On-site Landfill	Disposal On-site Ponds	Disposal Off-site	Sale or Beneficial Use: Sold	Used On-site	Used Off-site	Storage Stored On-site	Stored Off-site	Total
Fly ash from standard boiler/PCD units									
Fly ash from units with dry FGD			418.1	52.9		73.2			544.2
Fly ash from FBC units									
Bottom ash from standard boiler units			116.2			0.9			117.1
Bottom (bed) ash from FBC units									
FGD Gypsum									
Other FGD byproducts									
Ash from coal gasification (IGCC) units									
Other (specify via footnote on Schedule 9)									
Steam Sales (MMBtu)									

SCHEDULE 8. PART B. FINANCIAL INFORMATION

(Instructions for SCHEDULE 8 PART B are on page15.)

If actual data are not available, provide an estimated value.

Operation and Maintenance (O&M) Expenditures During Year (Thousand Dollars)

Type	(1) Fly Ash	(2) Bottom Ash	(3) Flue Gas Desulfurization	(4) Water Pollution Abatement	(5) Other Pollution Abatement	(6) Total (1 + 2 + 3 + 4 + 5)
Collection	2,961	773	14,172	0	2,207	20,113
Disposal						0
Other						0

Capital Expenditures for New Structures and Equipment During Year, Excluding Land and Interest Expense (Thousand Dollars)

Type	(7) Air Pollution Abatement	(8) Water Pollution Abatement	(9) Solid/Contained Waste	(10) Other Pollution Abatement
Amount	2,193	0	770	0

Byproduct Sales Revenue During Year (Thousand Dollars)

Type	(11) Fly Ash	(12) Bottom Ash	(13) Fly and Bottom Ash Sold Intermingled	(14) Flue Gas Desulfurization	(15) Other Byproduct Revenue	(16) Total (11+12+13+14+15)
Amount	211					211

SCHEDULE 8. PART C. BOILER INFORMATION NITROGEN OXIDE EMISSION CONTROLS

(Instructions for SCHEDULE 8 PART C are on page 16.)

Complete a separate row for each boiler.

Note: The Boiler ID must match the Boiler ID as reported on Form EIA-860, "Annual Electric Generator Report."

No NOX Controls

Boiler ID	NOx Control In-Service (hours)	NOx Emission Rate (lbs/MMBtu)	
		Entire Year	May through September
B1	6,166	.34	.34
B2	8,562	.34	.34

SCHEDULE 8. PART D. COOLING SYSTEM INFORMATION, MONTHLY OPERATIONS

(Instructions for SCHEDULE 8 PART D are on page 16.)

Note: Cooling System ID must match the ID as reported on Form EIA-860, "Annual Electric Generator Report."
Complete a separate row for each cooling system.

Cooling System ID	Status	Chlorine added to Cooling Water (1000 lbs)	Hours in Service	Average Annual Rate of Cooling Water (to nearest 0.1 ft^3/sec)				Maximum Cooling Water Temperature at Intake (F)			Maximum Cooling Water Temperature at Discharge Outlet (F)		
				Diversion	Withdrawal	Discharge	Consumption	Estimation	Monthly Avg	Monthly Max	Monthly Avg	Monthly Max	Estimation
Month 1													
CC1	OP	5	740	7.2	7.2	0	7.2	2	33	34			1
CC2	OP	5	744	7.2	7.2	0	7.2	2	33	34			1
Month 2													
CC1	OP	5	672	6.9	6.9	0	6.9	2	33	33			1
CC2	OP	5	672	6.9	6.9	0	6.9	2	33	33			1
Month 3													
CC1	OP	5	687	6.6	6.6	0	6.6	2	33	33			1
CC2	OP	5	743	4.3	7.3	0	7.3	2	33	33			1
Month 4													
CC1	OP	5	685	6.6	6.6	0	6.6	2	41	52			1
CC2	OP	3	720	7	7	0	7	2	41	52			1
Month 5													
CC1	OP	2	346	3	3	0	3	2	53	58			1
CC2	OP	5	744	7.2	7.2	0	7.2	2	53	57			1
Month 6													
CC1	OP	4	590	5.5	5.5	0	5.5	2	62	70			1
CC2	OP	5	720	7.2	7.2	0	7.2	2	62	70			1
Month 7													
CC1	OP	5	649	6.9	6.9	0	6.9	2	72	77			1
CC2	OP	6	744	8.5	8.5	0	8.5	2	72	77			1
Month 8													
CC1	OP	5	621	6.3	6.3	0	6.3	2	70	74			1
CC2	OP	4	516	5.6	5.6	0	5.6	2	70	74			1
Month 9													
CC1	OP	0	0	0	0	0	0	2	63	69			1

CC2	OP	6	720	7.9	7.9	0	7.9	2	63	69	1
Month 10											
CC1	OP	0	0	0	0	0	0	2	53	61	1
CC2	OP	5	744	7.5	7.5	0	7.5	2	53	61	1
Month 11											
CC1	OP	1	296	2.1	2.1	0	2.1	2	40	46	1
CC2	OP	5	720	6.4	6.4	0	6.4	2	40	46	1
Month 12											
CC1	OP	5	717	6.8	6.8	0	6.8	2	34	34	1
CC2	OP	5	743	6.3	6.3	0	6.3	2	34	34	1

SCHEDULE 8. PART E . FLUE GAS PARTICULATE COLLECTION INFORMATION

(Instructions for SCHEDULE 8 PART E are on page 17)

Complete a separate row for each flue gas particulate collector.

Does not Apply

Flue Gas Particulate Collector ID	Status	Hours in Service	Typical Particulate Emissions Rate (nearest 0.01 1b/MMBtu)	Removal Efficiency of Particulate Matter (nearest 0.1% by weight) At Annual Operating Factor	At 100% Load or Tested Efficiency	Date of Most Recent Efficiency Test (e.g., 12-2005)
BH1	OP	6,166	.02	99.9	99.9	09-1983
BH2	OP	8,562	.01	99.9	99.9	08-1986

SCHEDULE 8. PART F. FLUE GAS DESULFURIZATION UNIT INFORMATION, ANNUAL OPERATIONS

(Instructions for SCHEDULE 8 PART F are on page 19.)

Note: Flue Gas Desulfurization ID must match the ID as reported on Form EIA-860, "Annual Electric Generator Report."
Complete a separate row for each Flue Gas Desulfurization Unit.

ANNUAL OPERATIONS

Does not Apply

Flue Gas Desulfurization Unit ID	FGD Unit Status	Hours In Service	Quantity of FGD Sorbent Used (to nearest 0.1 thousand tons)	Electrical Energy Consumption (MWh)	Removal Efficiency of Sulfur Dioxide (nearest 0.1% by wt) At Annual Operating Factor	At 100% Load or Tested Efficiency	Date of Most Recent Efficiency Test (e.g., 12-2005)
FGD1	OP	6,166	30.4	17,000	85.1	63.9	09-1983
FGD2	OP	8,562	45	28	82.9	85.8	08-1986

OPERATION AND MAINTENANCE EXPENDITURES DURING YEAR, EXCLUDING ELECTRICITY (THOUSAND DOLLARS)

Flue Gas Desulurization Unit ID	Feed Materials and Chemicals	Labor and Supervision	Waste Disposal	Maintenance, Materials and All Other Costs	Total
FGD1	$2,837	$1,787	$291	$2,205	$7,120
FGD2	$3,874	$2,213	$403	$562	$7,052

U.S. Department of Energy
Energy Information Administration
Form EIA-923

EIA923 Power Plant Operations Report

Year: **2011** Plant: **6469** **Antelope Valley**

Form Approval
OMB No. 1905-0129
Approval Expires 12/31/2010

Schedule 9 Comments

Schedule	Part	Item	Comment

Error Log

Purchase Type	Fuel	Schedule	Prime Mover	Equipment ID	Rpt Month	Supplier		Error Number & Description/Override	Ranges
		8C		B1			853	Entire Year rate of NOX emissions per MMBtu of fuel burned falls outside of the typical range of 0.1 to 0.3 pounds per million Btu. Default	
		8C		B1			854	May to September rate of NOX emissions per MMBtu of fuel burned falls outside of the typical range of 0.1 to 0.3 pounds per million Btu. Default	
		8C		B2			853	Entire Year rate of NOX emissions per MMBtu of fuel burned falls outside of the typical range of 0.1 to 0.3 pounds per million Btu. Default	
		8C		B2			854	May to September rate of NOX emissions per MMBtu of fuel burned falls outside of the typical range of 0.1 to 0.3 pounds per million Btu. Default	
		8F		FGD1			852	Total O&M expenditures exceed typical expenses to operate FGD units at steam electric power plants Default	
		8F		FGD2			852	Total O&M expenditures exceed typical expenses to operate FGD units at steam electric power plants Default	

U.S. Department of Energy
Energy Information Administration
Form EIA-923

EIA923 Power Plant Operations Report

Year: **2011** Plant: **2817** **Leland Olds**

Form Approval
OMB No. 1905-0129
Approval Expires 12/31/2010

NOTICE: This report is mandatory under the Federal Energy Administration Act of 1974 (Public Law 93-275). Failure to comply may result in criminal fines, civil penalties and other sanctions as provided by law. For further information concerning sanctions and data protections see the provision on sanctions and the provision concerning confidentiality of information in the instructions. **Title 18 USC 1001 makes it a criminal offense for any person knowingly and willingly to make to any Agency or Department of the United States any false, fictitious, or fraudulent statements as to any matter within its jurisdiction.**

SCHEDULE 1. IDENTIFICATION

Survey Contact

Contact	Joseph Leingang	Submit By	300002472
Title	Director of Fuels	Submit Date	04-APR-12
Address	1717 E. Interstate Avenue	Accept By	
		Accept Date	
City/State/Zip	Bismarck ND 58503		
Email	jleingang@bepc.com	Phone (701) 557-5648	Fax (701) 557-5144

Supervisor of Contact Person for Survey

Contact	Terry Retterath		
Title	Industrial Engineer III		
Address	1717 E. Interstate Avenue		
City/State/Zip	Bismarck ND 58503		
Email	tlrat@bepc.com	Phone (701) 223-0441	Fax (701) 557-5144

Report For

Company Name	Basin Electric Power Coop		
Plant Name	Leland Olds		
Plant ID	2817	Plant County	Mercer
Plant Address	Hwy 200		
Plant City	Stanton	Plant State	ND

Regulated	[X] Yes	No
CHP	Yes	[X] No
CHP Efficiency		

For contact detail go to http://www.eia.doe.gov/oss/forms.html#eia-923

SCHEDULE 6. NONUTILITY ANNUAL SOURCE AND DISPOSITION OF ELECTRICITY

(Instructions for SCHEDULE 6 are on page 13)

SCHEDULE 6 collects calendar year data (no monthly detail).
Annual data are due by March 30 following the reporting year.
Report all generation in **megawatthours (MWh)** rounded to a whole number.

(1) Gross Generation (Annual)

(2) Other Incoming Electricity

(3) Total Sources (1 + 2)

(4) Station Use

(5) Direct Use

(6) Total Facility Use (4 + 5)

(7) Retail Sales to Ultimate Customers

(8) Sales for Resale (MWh)

(9) Other Outgoing Electricity

(10) Total Disposition (6 + 7 + 8+ 9)

Total Sources must equal Total Disposition (3 = 10)

Plants that cannot separate Station Use and Direct Use may enter zero in Station Use and the sum of Station Use and Direct Use in the Direct Use field.

SCHEDULE 7. ANNUAL REVENUES FROM SALES FOR RESALE

(Instruction for SCHEDULE 7 are on page 14.)

SCHEDULE 7 is to be completed by respondents who entered a positive amount on SCHEDULE 6, Disposition of Electricity, Item 8, Sales for Resale. Annual data are due by March 30 following the reporting year.

Sales for Resale is energy supplied to other electric utilities, cooperatives, municipalities, Federal and State electric agencies, or other entities for resale to end-use consumers.

Annual Revenues from Sales for Resale (in thousand dollars)

SCHEDULE 8. ANNUAL ENVIRONMENTAL INFORMATION

SCHEDULE 8. PARTS A through F are filed annually and must be reported by steam-electric organic-fueled power plants with a total steam turbine capacity of 100 megawatts and above (only plants that reported boiler-level consumption on SCHEDULE 3. Part A.). All steam-electric organic-fueled power plants with a total steam turbine capacity of 10 megawatts and above are responsible for filing Schedule 8, Parts C, E, and F. Annual data are due by March 30 following the reporting year.

SCHEDULE 8. PART A. ANNUAL BYPRODUCT DISPOSITION

(Instructions for SCHEDULE 8 PART A are on page 14)

Enter the quantity of combustion byproducts for the year by type of disposal (to nearest 0.1 thousand tons). Report sales of steam in million Btu (MMBtu). If actual data are not available, provide an estimated value.

No Byproducts

Byproduct	On-site Landfill	Disposal On-site Ponds	Disposal Off-site	Sale or Beneficial Use: Sold	Used On-site	Used Off-site	Storage Stored On-site	Stored Off-site	Total
Fly ash from standard boiler/PCD units			102.8	37.7					140.5
Fly ash from units with dry FGD									
Fly ash from FBC units									
Bottom ash from standard boiler units		102.8		21.0					123.8
Bottom (bed) ash from FBC units									
FGD Gypsum									
Other FGD byproducts									
Ash from coal gasification (IGCC) units									
Other (specify via footnote on Schedule 9)									
Steam Sales (MMBtu)									

SCHEDULE 8. PART B. FINANCIAL INFORMATION

(Instructions for SCHEDULE 8 PART B are on page15.)

If actual data are not available, provide an estimated value.

Operation and Maintenance (O&M) Expenditures During Year (Thousand Dollars)

Type	(1) Fly Ash	(2) Bottom Ash	(3) Flue Gas Desulfurization	(4) Water Pollution Abatement	(5) Other Pollution Abatement	(6) Total (1 + 2 + 3 + 4 + 5)
Collection	1,377	624	0	0	3	2,004
Disposal						0
Other						0

Capital Expenditures for New Structures and Equipment During Year, Excluding Land and Interest Expense (Thousand Dollars)

Type	(7) Air Pollution Abatement	(8) Water Pollution Abatement	(9) Solid/Contained Waste	(10) Other Pollution Abatement
Amount	4,046	0	398	0

Byproduct Sales Revenue During Year (Thousand Dollars)

Type	(11) Fly Ash	(12) Bottom Ash	(13) Fly and Bottom Ash Sold Intermingled	(14) Flue Gas Desulfurization	(15) Other Byproduct Revenue	(16) Total (11+12+13+14+15)
Amount	177	102				279

SCHEDULE 8. PART C. BOILER INFORMATION NITROGEN OXIDE EMISSION CONTROLS

(Instructions for SCHEDULE 8 PART C are on page 16.)

Complete a separate row for each boiler.

Note: The Boiler ID must match the Boiler ID as reported on Form EIA-860, "Annual Electric Generator Report."

No NOX Controls

Boiler ID	NOx Control In-Service (hours)	NOx Emission Rate (lbs/MMBtu)	
		Entire Year	May through September
1	6,659	.25	.25
2	7,199	.3	.3

SCHEDULE 8. PART D. COOLING SYSTEM INFORMATION, MONTHLY OPERATIONS

(Instructions for SCHEDULE 8 PART D are on page 16.)

Note: Cooling System ID must match the ID as reported on Form EIA-860, "Annual Electric Generator Report."
Complete a separate row for each cooling system.

Cooling System ID	Status	Chlorine added to Cooling Water (1000 lbs)	Hours in Service	Average Annual Rate of Cooling Water (to nearest 0.1 ft^3/sec)				Maximum Cooling Water Temperature at Intake (F)			Maximum Cooling Water Temperature at Discharge Outlet (F)		
				Diversion	Withdrawal	Discharge	Consumption	Estimation	Monthly Avg	Monthly Max	Monthly Avg	Monthly Max	Estimation
Month 1													
1	OP	0	744	158.8	158.8	158.6	.2	2	38	40	65	69	1
2	OP	0	744	313.9	313.9	313.6	.3	2	38	40	63	68	1
Month 2													
1	OP	0	672	155.1	155.1	154.9	.2	2	38	41	64	70	1
2	OP	0	672	310.5	310.5	310.2	.3	2	38	41	62	69	1
Month 3													
1	OP	0	743	148.5	148.5	148.3	.2	2	39	46	64	77	1
2	OP	0	743	299	299	298.7	.3	2	39	46	64	78	1
Month 4													
1	OP	0	720	105.7	105.7	105.6	.1	2	42	48	59	78	1
2	OP	0	720	228.4	228.4	228.1	.3	2	42	48	56	76	1
Month 5													
1	OP	0	59	0	0	0	0	2	49	62	46	55	1
2	OP	0	744	212.5	212.5	212.2	.3	2	49	62	67	98	1
Month 6													
1	OP	0	0	0	0	0	0	2					1
2	OP	0	720	192.6	192.6	192.5	.1	2	53	62	50	58	1
Month 7													
1	OP	0	614	90.2	90.2	90.1	.1	2	63	72	70	95	1
2	OP	0	744	191	191	190.8	.2	2	63	72	75	101	1
Month 8													
1	OP	0	744	154	154	153.9	.1	2	65	71	84	99	1
2	OP	0	744	255.3	255.3	255	.3	2	65	71	90	99	1
Month 9													
1	OP	0	720	149.8	149.8	149.6	.2	2	62	66	79	94	1

2	OP	0	720	263.3	263.3	263	.3	2	62	66	78	96	1
Month 10													
1	OP	0	744	154.1	154.1	154	.1	2	61	75	78	89	1
2	OP	0	744	293.6	293.6	293.3	.3	2	61	75	85	95	1
Month 11													
1	OP	0	720	156.6	156.6	156.5	.1	2	50	58	67	80	1
2	OP	0	720	298.8	298.8	298.5	.3	2	50	58	71	88	1
Month 12													
1	OP	0	744	149.6	149.6	149.4	.2	2	42	48	58	70	1
2	OP	0	744	295.6	295.6	295.3	.3	2	42	48	66	75	1

SCHEDULE 8. PART E . FLUE GAS PARTICULATE COLLECTION INFORMATION

(Instructions for SCHEDULE 8 PART E are on page 17)

Complete a separate row for each flue gas particulate collector.

Does not Apply

Flue Gas Particulate Collector ID	Status	Hours in Service	Typical Particulate Emissions Rate (nearest 0.01 1b/MMBtu)	Removal Efficiency of Particulate Matter (nearest 0.1% by weight) At Annual Operating Factor	At 100% Load or Tested Efficiency	Date of Most Recent Efficiency Test (e.g., 12-2005)
1	OP	6,659	.02	99.8	99.8	12-1974
2	OP	7,199	.02	99.5	99.5	12-1976

SCHEDULE 8. PART F. FLUE GAS DESULFURIZATION UNIT INFORMATION, ANNUAL OPERATIONS

(Instructions for SCHEDULE 8 PART F are on page 19.)

Note: Flue Gas Desulfurization ID must match the ID as reported on Form EIA-860, "Annual Electric Generator Report."
Complete a separate row for each Flue Gas Desulfurization Unit.

ANNUAL OPERATIONS

[X] Does not Apply

Flue Gas Desulfurization Unit ID	FGD Unit Status	Hours In Service	Quantity of FGD Sorbent Used (to nearest 0.1 thousand tons)	Electrical Energy Consumption (MWh)	Removal Efficiency of Sulfur Dioxide (nearest 0.1% by wt) At Annual Operating Factor	At 100% Load or Tested Efficiency	Date of Most Recent Efficiency Test (e.g., 12-2005)

OPERATION AND MAINTENANCE EXPENDITURES DURING YEAR, EXCLUDING ELECTRICITY (THOUSAND DOLLARS)

Flue Gas Desulurization Unit ID	Feed Materials and Chemicals	Labor and Supervision	Waste Disposal	Maintenance, Materials and All Other Costs	Total

U.S. Department of Energy
Energy Information Administration
Form EIA-923

EIA923 Power Plant Operations Report

Year: **2011** Plant: **2817** **Leland Olds**

Form Approval
OMB No. 1905-0129
Approval Expires 12/31/2010

Schedule 9 Comments

Schedule	Part	Item	Comment

Error Log

Purchase Type	Fuel	Schedule	Prime Mover	Equipment ID	Rpt Month	Supplier		Error Number & Description/Override	Ranges
		8A					844	Total volume of fly ash is an unexpectedly high or low portion of the combined total of fly ash and bottom ash; please check. Default	