

June 22, 2018

Mr. Randy Christmann, Commissioner
North Dakota Public Service Commission
Capitol Building
600 E. Boulevard Ave.
Bismarck, ND 58505

Dear Commissioner Christmann:

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 9 copies of the plan.

Sincerely,

A handwritten signature in blue ink, appearing to read "Paul M. Sukut", with a long, sweeping tail.

Paul M. Sukut
CEO & General Manager

vW
ATTACHMENT

1 PU-18-211 Filed 06/22/2018 Pages: 82
2018 Ten Year Plan
Basin Electric Power Cooperative
Paul Sukut, CEO & General Manager

STATE OF NORTH DAKOTA)
)
COUNTY OF BURLEIGH)

AFFIDAVIT OF MAILING

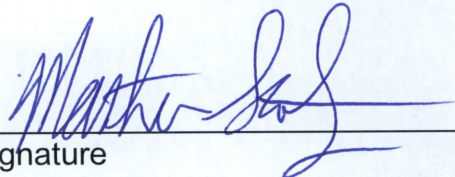
I hereby certify that the following list contains the names and last address of each designated state agency and/or state official given notice of filing of the Basin Electric Power Cooperative Ten Year Plan pursuant to the Rules and Regulations of the North Dakota Public Service Commission governing 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

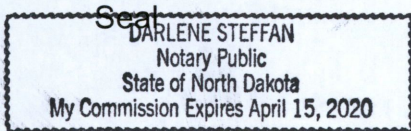
See Exhibit A Attached

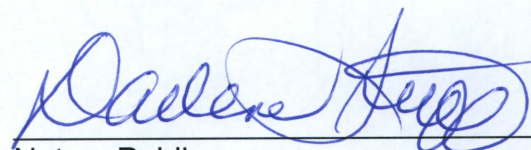
See Exhibit A Attached



Signature

On this 19 day of June, 2018, Matthew Stoltz known to me, under oath deposed and said the above Affidavit of Mailing is true and correct.





Notary Public

Mail to: Public Service Commission
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EXHIBIT A

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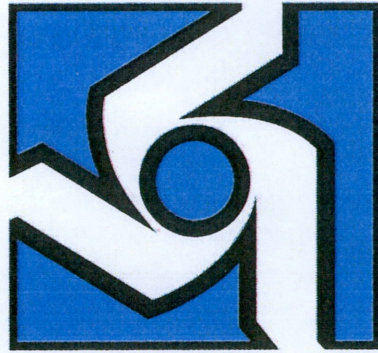
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BASIN ELECTRIC POWER COOPERATIVE

A Touchstone Energy[®] Cooperative 

NORTH DAKOTA TEN YEAR PLAN

2018

TABLE OF CONTENTS

	<u>Page</u>
INTRODUCTION	1
SECTION A: Existing Energy Conversion Facilities	1
SECTION B: Energy Conversion Facilities under construction	2
SECTION C: Proposed Energy Conversion Facilities on which construction is intended within the Ensuing Five Years	2
SECTION D: Proposed Energy Conversion Facilities during the next Ten Year Time Period	2
SECTION E: Existing Transmission Facilities (Electric)	2
SECTION F: Existing Transmission Facilities (Pipeline)	4
SECTION G: Proposed Transmission Facilities on which construction is intended within the Ensuing Five Years (Electric)	4
SECTION H: Proposed Transmission Facilities on which construction is intended within the Ensuing Five Years (Pipeline)	4
SECTION I: Proposed Transmission Facilities during the next Ten Year Time Period (Electric and Pipeline)	5
SECTION J: Regional Coordination	5
SECTION K: Environmental Information	7
SECTION L: Projected Demand for Services	8
EXHIBIT 1: Form EIA-923 (distributed only to the Public Service Commission)	
EXHIBIT 2: Summer/Winter Loads	
EXHIBIT 3: Eastern System Summer/Winter Load Resources	

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 five subsidiaries: Dakota Gasification Company, Dakota Coal Company, Montana Limestone Company, Wyoming Line Producers, and Souris Valley Pipeline LTD. 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 sixteen existing energy conversion facilities. Six of these facilities are in North Dakota; the Antelope Valley Station near Beulah; the Leland Olds Station near Stanton; Prairie Winds ND1 near Minot; the Minot Wind Project near Minot; the Pioneer Generation Station near Williston; and the Lonesome Creek Generation Station near Watford City. 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; Deer Creek Station near Brookings, South Dakota; Wisdom Unit 2 at Spencer, Iowa; and the Culbertson Generation Station near Culbertson, Montana.

Basin Electric purchases all 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. Basin Electric also purchases all the output from the 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 Project near Groton, South Dakota; the Campbell County Wind Project near Pollock, South Dakota; and the Pipestone, Minnesota School District Wind Turbine. Basin Electric purchases 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; 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 does not have any energy conversion facilities under construction.

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

Basin Electric is evaluating the development of new generating resources (coal, gas, and wind) to meet Basin Electric's forecasted load growth as it materializes and continue to meet the 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, nuclear, 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**

<u>LINES - BY VOLTAGE</u>	<u>COMMERCIAL IN-SERVICE DATE</u>
<u>69 kV Lines</u>	
Leland Olds - Basin Electric Sub	01/09/66
<u>115 kV Lines</u>	
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
Blaisdell-Berthold	12/21/13
Blaisdell-Plaza	02/01/18
<u>230 kV Lines</u>	
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
Judson-Williston	12/22/15
Tande-Neset	10/31/17

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 #1	11/30/83
Antelope Valley Station-Charlie Creek #2	09/18/15
Charlie Creek-Judson	12/22/15
Judson-Kummer Ridge	09/27/16
Judson-Tande	10/31/17

500 kV Lines

Antelope Valley Station-Huron, SD (345 kV operation)	07/01/84
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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
230/115 kV Blaisdell Substation	05/24/12
230/115 kV Wheelock Substation	10/16/12
345/230 kV Judson Substation	12/22/15
345/115 kV Roundup Substation	09/18/15
345/115 kV Patent Gate Substation	12/22/15
345/115 kV Kummer Ridge Substation	09/27/16
345/230 kV Tande Substation	10/31/17

- 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, a 12 mile long natural gas fuel supply pipeline associated with the Groton Generation Station, and a 13 mile long natural gas fuel supply pipeline associated with the Deer Creek 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.

DGC constructed a 3.5 mile, 10' diameter natural gas pipeline, in late 2013, with the sole purpose to provide AVS with access to natural gas for use only during startup activities.

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

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)

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

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

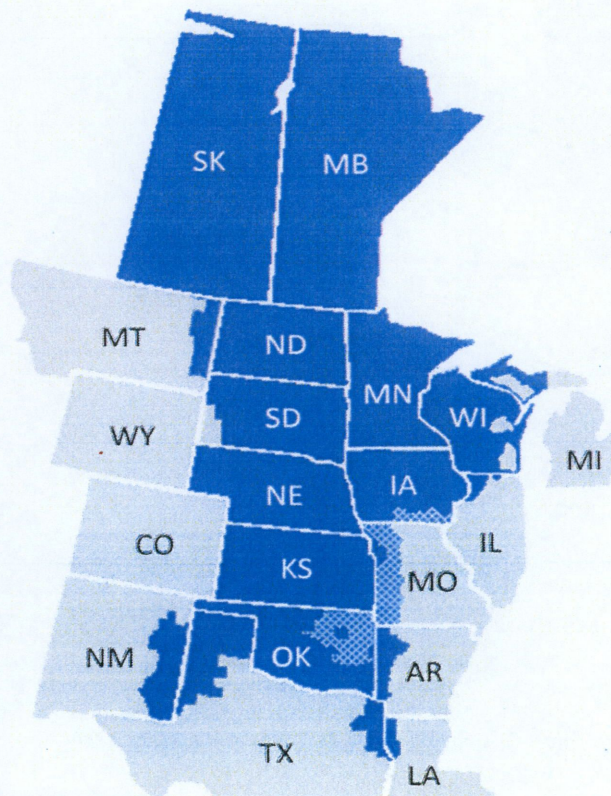
Results of the development of new generating resources (refer to section D) will identify transmission improvements necessary required by the new resources. Transmission studies are underway to analyze the required transmission improvements to accommodate network load growth. Results of these studies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

SECTION J: REGIONAL COORDINATION

Midwest Reliability Organization

Midwest Reliability Organization (MRO) is a non-profit organization dedicated to ensuring the reliability and security of the bulk power system in the north central region of North America, including parts of both the United States and Canada. MRO is one of seven regional entities in North America operating under authority from regulators in the United States through a delegation agreement with the North American Electric Reliability Corporation (NERC) and in Canada through arrangements with provincial regulators. The region includes more than 100 organizations that are involved in the production and delivery of power to more than 20 million people.

The primary purpose of MRO is to ensure compliance with reliability standards and perform regional assessments of the grid's ability to meet the demands for electricity.



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.

Southwest Power Pool

Basin Electric joined the Southwest Power Pool (SPP) in 2015. SPP oversees the bulk electric grid and wholesale power market in the central United States on behalf of a diverse group of utilities and transmission companies in 14 states including North Dakota. SPP establishes practices for system design, planning, adequacy, regional transmission service tariffs, interconnections, operation, reliability, market designs and efficiency, and market power mitigation that will help to assure efficient and reliable power supply among the systems in SPP and SPP transmission customers. Basin Electric participates on various committees and work groups as a function of SPP.

Midcontinent Independent System Operator

MISO is a not-for-profit member-based organization that ensures reliable, least-cost delivery of electricity across all or parts of 15 U.S. states and one Canadian province. In cooperation with stakeholders, MISO manages approximately 65,000 miles of high-voltage transmission and 200,000 megawatts of power-generating resources across its footprint.

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 and Members 1st Power Cooperative, Class A members 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).

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.

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 that have a federal nexus adhere to the requirements of the associated Federal Agency 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 sales to its Class A and D 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 2018. 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 20-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 our member systems. Historical energy data is combined with external data obtained from government and private sector sources as well as membership consultation 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.; IHS Markit, the US Department of Energy, Washington, D.C.; along with various other sources.

Basin Electric's service area is electrically divided into four assessment areas across two electrical interconnections. The majority of Basin Electric's system resides in the eastern interconnection consisting of the Southwest Power Pool (SPP) and Midcontinent Independent System Operator (MISO) assessment areas. In the western interconnection Basin Electric's system resides in the Northwest Power Pool (NWPP) and the Rocky Mountain Reserve Group assessment areas. These interconnections 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 across all 4 assessment areas.

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

Leland Olds Station: Leland Olds Unit 1 was placed in-service on January 9, 1966 and is a base-load coal fueled unit located near Stanton, ND with a net capacity of 222 MW. Leland Olds Unit 2 is a coal fueled unit that was placed in-service on December 15, 1975 and its net capacity is rated at 445 MW. Basin Electric installed emission control equipment at the Leland Olds Station which required an increase to the station service. This equipment was put in service after the 2012 fall outage on Unit 2 reducing the net capacity from 448 MW

to 445 MW due to additional station service required. The Unit 1 emissions control equipment was placed into service after the spring 2013 maintenance outage.

Antelope Valley Station: Basin Electric operates two 450 MW (net) thermal-generating base-load coal fired units near Beulah, ND. Unit 1 began commercial operation on July 1, 1984 and Unit 2 began partial commercial operation on June 1, 1986.

Designed to be environmentally sound, over \$394 million have been invested in capital pollution control asset investments for AVS to date. Dry Scrubbers use lime to capture and remove up to 90 percent of sulfur dioxide emissions from stack gases. Fabric filter bag houses capture and remove up to 99 percent of particulate matter. Each bag house contains more than 8,000, 35-foot tall bags. AVS is a "zero-discharge" facility; even water is used efficiently only leaving the plant site through evaporation.

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. 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) until the SCR and SNCRs installations are complete, expected by June 2019, after which Basin Electric's share of the unit will be reduced to around 39-40 MW (net).

Spirit Mound Station: Basin Electric placed in service two 60 MW (net) nameplate fuel 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.

Earl F. 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. In accordance with the Utility Mercury and Air Toxics Standards (MATs), Unit 1 stopped burning coal in January of 2014. Corn Belt and Basin Electric completed a retrofit of Unit 1 to switch from coal to natural gas for fuel. This retrofit was completed in June of 2014.

Earl F. 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;

therefore, Basin Electric has 93.75% or 75 MW from the 80 MW combustion turbine.

Groton Generation Station: The Groton Station is located near Groton, SD. Basin Electric commissioned Groton Unit 1 in 2006 and Unit 2 in 2008. These LMS 100 natural gas units provide peaking power. Unit 1 has a winter rating of 98 MW and Unit 2 has a winter rating of 97 MW.

Culbertson Generation Station: The Culbertson Station is located near Culbertson, MT. Basin Electric commissioned Culbertson Unit 1 in 2010. The LMS 100 natural gas unit provides peaking power. The unit has a winter rating of 91 MW.

Deer Creek Station: The Deer Creek Station is located near Brookings, SD. Basin Electric commissioned the Deer Creek Station in August of 2012. The unit is a combined cycle natural gas facility that provides intermediate power. The unit has a winter rating of 300 MW.

Pioneer Generation Station: The Pioneer Station northwest of Williston, ND was built to serve the increasing demand for electricity by member cooperatives in northwest North Dakota.

Unit 1 started commercial operation in 2013, Unit 2 and Unit 3 started commercial operation in 2014. Each of the three units has 45 MW of generation capacity giving the station a total rating of 135 MW.

Unit 1 of Pioneer Generation Station features a clutch that allows the turbine to uncouple from the generator, allowing the generator to provide transmission system voltage support. This feature, if needed, is used to provide fast-acting reactive power which will stabilize the transmission system in the area.

Phase III of the station, which started commercial operation in 2017, features first-of-its-kind engines for Basin Electric: 12 natural gas-based reciprocating engines, each with a generating capacity of 9.3 MW.

Lonesome Creek Generation Station: The Lonesome Creek Station is located near Watford City, ND. Commercial operation for Lonesome Creek Unit 1 began in December 2013, Units 2 and 3 in January 2015, and Units 4 and 5 in March 2017. Each unit consists of a LM 6000 natural gas unit and provides peaking power. Each unit has a winter rating of 45 MW for a total station generation capacity is 225 MW. Unit 1 has a synchronous clutch located between the combustion turbine and generator allowing the generator rotor to spin independent of the turbine providing voltage stability to the electric grid.

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.

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.

PrairieWinds 1: Basin Electric 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.

Crow Lake Wind Project: Basin Electric 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 in 2011. Basin Electric owns 107 turbines or 160.5 MW. Basin Electric has a purchase power contract with Mitchell Technical Institute for the power out of the last turbine.

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 and for Basin Electric to return a like amount of energy to Western during off-peak period.

George 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.

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.

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, Com Belt entered into a wholesale power contract with Basin Electric whereby Basin Electric will sell and deliver to Com Belt all of Com Belt's capacity and energy requirements in excess of the power and energy available to Com Belt from the Western Area Power Administration.

Western Native American Purchase: Basin Electric receives a Native American Allocation of 39.7 MW in the winter and 40.8 MW in the summer season. This allocation is a result of congressional action that made federal power available to the Native Americans.

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 load located on eastern system using capacity and/or energy from west side resources and vice versa. The Basin Electric ownership percentage is 65% and the Black Hills Power, Inc. ownership percentage is 35%. Currently, Basin Electric has rights to 130 MW of the tie.

Stegall (David Hamill) DC Tie: Tri-State G&T Association constructed a 110 MW asynchronous tie at Stegall, NE. Basin Electric has acquired all rights to this tie. This enables Basin Electric to serve load located on the eastern system using capacity and/or energy from west side resources and vice versa.

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.

Long-Term Resource:

- Wind Purchases:
 - 40 MW west of Edgeley, ND
 - two 49.5 MW projects near Wilton, ND
 - 100 MW near Baldwin, ND
 - 40 MW near Highmore SD
 - 94 MW near Pollock, SD
 - 99 MW near Groton, SD
 - 104 MW near Hebron, ND
 - 150 MW near Tioga, ND
 - Two 150 MW projects near New England, ND
 - 200 MW near Columbus, ND (expected COD 12/2019)
 - 200 MW near Avon, SD (expected COD 12/2019)

- Peaking Purchases:
 - 10 MW City of Madison, SD diesel generators
 - Eight 5.5 MW waste heat recover units from Ormat Technologies Inc. (3 sites in SD near Wetonka, Clark, and Estelline; 3 in ND; 1 in MT; 1 in MN)
 - 92 MW in purchases from CBPC
 - 24.8 MW from Webster City, IA
 - 12.1 MW from Estherville, IA
 - 10 MW from Spencer, IA
 - 45.1 MW from their share of the Superior, Lakota, Hancock, and Crosswinds wind projects in IA
 - ~70 MW from North Iowa Municipal Electric Cooperative Association's (NIMECA's) surplus capacity resources in IA

- Other Long Term PPAs:
 - Capacity and Energy
 - 100 MW from Minnesota Power (ending 4/2020)
 - 50 MW from Heartland Consumers Power District (ending 5/2021)
 - 200 MW during the summer from Minnkota Power Cooperative (ending 11/2018)
 - 100 MW during the summer from Minnkota Power Cooperative (3/2019-5/2022)
 - Capacity Only
 - 100 MW from Minnesota Power (ending 5/2018)
 - 50 MW from Minnesota Power (6/2017-5/2019)
 - 50 MW from Minnesota Power (6/2018-5/2019)
 - 75-125 MW from Minnesota Power (6/2022-5/2025)
 - 25 MW from Great River Energy (ending 5/2019)
 - 75 MW from Great River Energy (6/2020-5/2023)
 - 25 MW from Xcel Energy/Northern States Power (ending 5/2019)
 - 50 MW from Manitoba Hydro (ending 5/2021)
 - 75-175 MW from Dairyland Power Cooperative (6/2019-5/2023)
 - 150 MW from Missouri River Energy Services (ending 9/2023)
 - 75 MW from NRG Power Marketing (6/2023-5/2025)

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:

Laramie River Station: The Laramie River Station capacity that Basin Electric will receive from Unit 2 and Unit 3 on the west is 675 MW (net) until June 2019 when the installation of the SCR and SNCRs at the station are expected to be completed and each owner's entitlement shares slightly adjusted. This will cause Basin Electric's share to increase from 675 MW (net) to about 678 MW (net).

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.

Wyoming Distributed Generation: The Wyoming Distributed Generation consists of 9 peaking 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. These units were released for commercial operation in 2002. These units currently are utilized for meeting our operating reserves for Basin Electric's west side electrical requirements.

Dry Fork Station: The Dry Fork Station is a 405 MW (net) coal fired power plant located 10 miles north of Gillette, Wyoming. This station was released for commercial operation in 2011. Basin Electric owns 92.9% of the station or 376 MW.

Long Term PPAs: Basin Electric has secured the following purchases for firm energy in the NWPP region.

- 50MW from PPL Energy Plus (ending 4/2020)
- 50 MW from MacQuarie Energy (formerly "Cargill"; ending 12/2021)
- 50-75 MW from MacQuarie Energy (formerly "Cargill"; 5/2020-12/2025)
- 100-150 MW from Morgan Stanley Capital Group (1/2019-12/2027)

The load values contained in Exhibit 2 were obtained from the econometric based load forecast. Loads in North Dakota are located in SPP and MISO Local Resource Zone 1 assessment areas so Basin Electric's loads in each of these areas 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:

<u>Plant</u>	<u>Fuel Source</u>	<u>Transportation</u>
Leland Olds Station	ND Lignite Coal	Rail
Spirit Mound Station	Oil	Pipeline
Laramie River Station	Wyoming (PRB) Coal	Rail
Antelope Valley Station	ND Lignite Coal	Mine Mouth/Rail
Minot Wind Project	Wind	N/A
Wyoming Distributed Gen	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 Gen Station	Natural Gas	Pipeline
Deer Creek Station	Natural Gas	Pipeline
Dry Fork Station	Wyoming (PRB) Coal	Mine Mouth
Pioneer Gen Station	Natural Gas	Pipeline
Lonesome Creek Gen Station	Natural Gas	Pipeline

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 cooperative.

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 Service Commission)**

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

Supplemental EIA923 Power Plant Operations Report
Year: **2016** Plant: **6469** **Antelope Valley**

Form Approval
OMB No. 1905-0129
Approval Expires 03/31/2020

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

Is this a regulated utility plant	<input checked="" type="checkbox"/> Yes	<input type="checkbox"/> No
Is this a combined heat and power plant	<input type="checkbox"/> Yes	<input checked="" type="checkbox"/> No
Enter the total plant efficiency of the combined heat and power plant	<input type="text"/>	%

Survey Contact

Contact	Erin Dukart	Submit Date	23-MAY-17
Title	Environmental Compliance Coordinator		
Address	1717 E. Interstate Avenue		
City/State/Zip	Bismarck	ND	58503
Email	edukart@bepc.com	Phone	(701) 557-5557
		Fax	

Supervisor of Contact Person for Survey

Contact	Joseph Leingang		
Title	Director of Fuels		
Address	1717 E. Interstate Avenue		
City/State/Zip	Bismarck	ND	58503
Email	jleingang@bepc.com	Phone	(701) 557-5648
		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

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).
Report all generation in **megawatthours (MWh)** rounded to a whole number.

- | | |
|--------------------------------|---|
| (1) Gross Generation (Annual) | (4) Station Use |
| (2) Other Incoming Electricity | (5) Direct Use |
| | (6) Total Facility Use (4 + 5) |
| | (7) Retail Sales to Ultimate Customers |
| | (8) Sales for Resale (MWh) |
| | (9) Provided Tolling Agreement (MWh) |
| | (10) Other Outgoing Electricity |
| (3) Total Sources (1 + 2) | (11) Total Disposition (6 + 7 + 8 + 9 + 10) |

Total Sources must equal Total Disposition (3 = 11)

**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.**

Types of Other Incoming Electricity
List all of the types of incoming electricity included in (2)
Other Incoming Electricity

Types of Other Outgoing Electricity
List all of the types of outgoing electricity in item (10)
Other Outgoing Electricity

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

Supplemental EIA923 Power Plant Operations Report
Year: **2016** Plant: **6469** **Antelope Valley**

Form Approval
OMB No. 1905-0129
Approval Expires 03/31/2020

SCHEDULE 7. PART A. ANNUAL REVENUES FROM SALES FOR RESALE TOAL

Complete Schedule 7, Part A, only if a positive value was entered on Schedule 6, Item (8): "Sales for Resale."

Sales for Resale are energy supplied to electric utilities, cooperatives, municipalities, federal and state elecytic agencies, power marketers, or other entities, for resale to end-use consumers.

Report in thousand dollars. For example \$1,987,234 should be entered as 1,987

Annual Revenues from Sales for Resale (in thousand dollars)

SCHEDULE 7. PART B. ANNUAL RETAIL SALES, REVENUES AND NUMBER OF CUSTOMERS FROM RETAIL SALES

Report by state and end-use customer sectors (Residential, Commercial, industrial and Transportation).

Complete an individual Schedule 7, Part B, for each state where customers are located, only if a positive value was entered on Schedule 6, Item (7), "Retail Sales to Ultimate Customers."

Annual Retail Sales, Revenue, and Number of Customers:

- Retail sales are sold directly to an end-use customer (i.e., the energy is consumed by the customer, onsite, and is not resold to other customers).
- Enter annual retail sales, revenue, and number of customers for each state where customer(s) are located.
- Report Annual Retail Sales in megawatthours (Mwh), by sector.
- Report Annual Revenue in thousand dollars, by sector.
- Report Number of Customers, by sector.

State					
Items	Residential	Commercial	Industrial	Transportation	Total
Retail Sales (Mwh)					
Revenue (\$ 000's)					
Number of Customers					

SCHEDULE 8. PART B. FINANCIAL INFORMATION RELATED TO COMBUSTION BY-PRODUCTS

Complete an individual Schedule 8, Part B, annually, for each organically fueled thermoelectric power plant with a total steam turbine capacity greater than, or equal to, 100 megawatts.

- Data reported in Schedule 8, Part B must correspond to the combustion by-product data reported on Schedule 8, Part A.
- If actual data are not available, provide an estimate value.
- Report all values in thousand dollars, to the nearest thousand.

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	2,128	821	19,267	0	1,447	23,663
Disposal						
Other						

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	15	0	251	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	0	0	0	0	0	0

SCHEDULE 8. PART C. AIR EMISSIONS CONTROL INFORMATION

Annual Operations																							
Environmental Equipment and/or Technology Type							NOx Emission Rate (lbs/MMBtu)		Particulate Matter Control				Sulfur Dioxide Control					Mercury Control		Acid Gas Control			
Types	PM Control ID	SO2 CONTROL ID	NOX Control ID	Mercury Control	Status	Hours in Service	Entire Year	May through September	Emission Rate (0.01 lb/MMBtu)	Removal Efficiency Rate at AOF	Tested Efficiency Particulate Removal (at 100% Load)	Test Date MM-YYYY	Removal Efficiency Rate at AOF	Removal Tested Efficiency (at 100% Load)	Test Date MM-YYY	Quantity of FGD Sorbent Used (nearest 0.1 thousand tons)	FGD Unit Electrical Energy Consumption	Removal Efficiency (nearest 0.1% by weight)	Emission Rate (0.01 lbs/Tbtu)	Removal Efficiency (nearest 0.1% by weight)			
Flue Gas Desulfurization Unit ID					Feed Materials and Chemicals		FGD Operation and Maintenance Expenditures During Year, Excluding Electricity (Thousand Dollars)										Maintenance, Material and All Other Costs					Total	
							Land and Supervision					Waste Disposal											
FGD1					\$5,270		\$2,901					\$655					\$1,189					\$10,015	
FGD2					\$4,083		\$2,248					\$507					\$2,413					\$9,251	

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

Complete an individual Schedule 8, Part D for each thermoelectric power plant (organically fueled, nuclear and combined cycle) with a total steam capacity greater than, or equal to, 100 megawatts.

- Complete a separate schedule for each reporting month.
- Complete a separate row for each cooling system.
- If actual data are not available, provided an estimated value.
- If the source of cooling water is a well or municipal water system, do not complete the Cooling Water Temperature sections.

Cooling System ID	Cooling System Type	Cooling System Status	Annual Amt of Hours Chlorine in added to Service Per Cooling Water (1000 lbs)	Average Monthly Rate of Cooling Water (to nearest 0.1 gallons per minute)				Cooling Water Temperature (degrees Fahrenheit)					Volume Cooling Water (to nearest 0.001 million gallons per month)						
				Div	Withdrawal	Discharge	Consumption	Method of Measure	Avg at Intake	Max at Intake	Avg at Discharge	Max at Discharge	Method of Measure	Div	Withdrawal	Discharge	Consumption		
Report Month 1																			
CC1	RF	OP	744	2.92	3027	3027	0	3027	2	32					7	135.123	135.123	0	135.123
Report Month 2																			
CC1	RF	OP	644	2.445	2709	2709	0	2709	2	32					7	113.143	113.143	0	113.143
Report Month 3																			
CC1	RF	OP	543	1.92	1990	1990	0	1990	2	39					7	88.825	88.825	0	88.825
Report Month 4																			
CC1	RF	OP	717	2.444	3689	3689	0	3689	2	48					7	159.36	159.36	0	159.36
Report Month 5																			
CC1	RF	OP	697	3.542	3671	3671	0	3671	2	60					7	163.895	163.895	0	163.895
Report Month 6																			
CC1	RF	OP	718	3.868	4142	4142	0	4142	2	70					7	178.956	178.956	0	178.956

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

Complete an individual Schedule 8, Part D for each thermoelectric power plant (organically fueled, nuclear and combined cycle) with a total steam capacity greater than, or equal to, 100 megawatts.

- Complete a separate schedule for each reporting month.
- Complete a separate row for each cooling system.
- If actual data are not available, provided an estimated value.
- If the source of cooling water is a well or municipal water system, do not complete the Cooling Water Temperature sections.

Cooling System ID	Cooling System Type	Cooling System Status	Annual Amt of Hours Chlorine in added to Service Cooling Water (1000 lbs)	Average Monthly Rate of Cooling Water (to nearest 0.1 gallons per minute)				Cooling Water Temperature (degrees Fahrenheit)					Volume Cooling Water (to nearest 0.001 million gallons per month)						
				Div	Withdrawal	Discharge	Consumption	Method of Measure	Avg at Intake	Max at Intake	Avg at Discharge	Max at Discharge	Method of Measure	Div	Withdrawal	Discharge	Consumption		
Report Month 7																			
CC1	RF	OP	665	3.505	3633	3633	0	3633	2	72					7	162.172	162.172	0	162.172
Report Month 8																			
CC1	RF	OP	744	3.875	4016	4016	0	4016	2	70					7	179.301	179.301	0	179.301
Report Month 9																			
CC1	RF	OP	720	3.666	3926	3926	0	3926	2	61					7	169.606	169.606	0	169.606
Report Month 10																			
CC1	RF	OP	744	3.518	3647	3647	0	3647	2	52					7	162.798	162.798	0	162.798
Report Month 11																			
CC1	RF	OP	720	3.224	3452	3452	0	3452	2	38					7	149.155	149.155	0	149.155
Report Month 12																			
CC1	RF	OP	651	2.69	2788	2788	0	2788	2	32					7	124.47	124.47	0	124.47

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

Complete an individual Schedule 8, Part D for each thermoelectric power plant (organically fueled, nuclear and combined cycle) with a total steam capacity greater than, or equal to, 100 megawatts.

- Complete a separate schedule for each reporting month.
- Complete a separate row for each cooling system.
- If actual data are not available, provided an estimated value.
- If the source of cooling water is a well or municipal water system, do not complete the Cooling Water Temperature sections.

Cooling System ID	Cooling System Type	Cooling System Status	Annual Amt of Hours Chlorine in added to Service Cooling Water (1000 lbs)	Average Monthly Rate of Cooling Water (to nearest 0.1 gallons per minute)				Cooling Water Temperature (degrees Fahrenheit)					Volume Cooling Water (to nearest 0.001 million gallons per month)						
				Div	Withdrawal	Discharge	Consumption	Method of Measure	Avg at Intake	Max at Intake	Avg at Discharge	Max at Discharge	Method of Measure	Div	Withdrawal	Discharge	Consumption		
Report Month 1																			
CC2	RF	OP	744	2.041	3152	3152	0	3152	2	32					7	140.613	140.613	0	140.613
Report Month 2																			
CC2	RF	OP	633	2.433	2696	2696	0	2696	2	32					7	112.479	112.479	0	112.479
Report Month 3																			
CC2	RF	OP	718	2.692	2790	2790	0	2790	2	39					7	124.437	124.437	0	124.437
Report Month 4																			
CC2	RF	OP	23	.095	101	101	0	101	2	48					7	4.374	4.374	0	4.374
Report Month 5																			
CC2	RF	OP	0	0	0	0	0	0	2						0	0	0	0	0
Report Month 6																			
CC2	RF	OP	205	.978	1048	1048	0	1048	2	70					7	45.237	45.237	0	45.237

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

Complete an individual Schedule 8, Part D for each thermoelectric power plant (organically fueled, nuclear and combined cycle) with a total steam capacity greater than, or equal to, 100 megawatts.

- Complete a separate schedule for each reporting month.
- Complete a separate row for each cooling system.
- If actual data are not available, provided an estimated value.
- If the source of cooling water is a well or municipal water system, do not complete the Cooling Water Temperature sections.

Cooling System ID	Cooling System Type	Cooling System Status	Service Per month	Annual Amt of Chlorine in Cooling Water (1000 lbs)	Average Monthly Rate of Cooling Water (to nearest 0.1 gallons per minute)				Method of Measure	Cooling Water Temperature (degrees Fahrenheit)					Volume Cooling Water (to nearest 0.001 million gallons per month)				
					Div	Withdrawal	Discharge	Consumption		Avg at Intake	Max at Intake	Avg at Discharge	Max at Discharge	Method of Measure	Div	Withdrawal	Discharge	Consumption	
Report Month 7																			
CC2	RF	OP	744	3.907	4049	4049	0	4049	2	72					7	180.607	180.607	0	180.607
Report Month 8																			
CC2	RF	OP	744	3.897	4039	4039	0	4039	2	70					7	180.174	180.174	0	180.174
Report Month 9																			
CC2	RF	OP	472	2.311	2475	2475	0	2475	2	61					7	106.83	106.83	0	106.83
Report Month 10																			
CC2	RF	OP	744	3.494	3621	3621	0	3621	2	52					7	161.537	161.537	0	161.537
Report Month 11																			
CC2	RF	OP	720	3.129	3352	3352	0	3352	2	38					7	144.676	144.676	0	144.676
Report Month 12																			
CC2	RF	OP	744	2.978	3086	3086	0	3086	2	32					7	137.664	137.664	0	137.664

SCHEDULE 9. COMMENTS
 (Instructions for SCHEDULE 9. are on page 20.)

Schedule	Part	Item	Comments
8	B	1-6	Cost accounting granularity does not go any finer than this level of aggregation, so Collection, Disposal and Other are aggregated in "Collection". Direct questions on this matter to jleingang@bepec.com
8	C	OT	OT should be SD
8	D	17	Data is from USGS

Generator Id	Retirement		Generator Retirement Dates
	Month	Year	Comments
	Changes in Ownership (Provide name of purchaser and date sold.)		

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

Supplemental EIA923 Power Plant Operations Report
Year: **2016** Plant: **6469** **Antelope Valley**

Form Approval
OMB No. 1905-0129
Approval Expires 03/31/2020

ERRORS

Purchase Type	Fuel	Schedule	Prime Mover	Equipment ID	Rpt Month	Supplier	Error Number & Description	Ranges	Override Comment
		8C		FGD1/S			850 The Removal Efficiency at Annual Operating Factor for sulfur dioxide is outside the expected range. Expected range is within 50%-99%. If correct, enter a comment to explain data out of typical range.		Low Loads
		8D					864 The code for "Other" was selected for the 'Measured or Estimated' Water Temperature. Specify the method in an override comment.		Data is from USGS

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SCHEDULE 1. IDENTIFICATION

Is this a regulated utility plant	<input checked="" type="checkbox"/> Yes	<input type="checkbox"/> No
Is this a combined heat and power plant	<input type="checkbox"/> Yes	<input checked="" type="checkbox"/> No
Enter the total plant efficiency of the combined heat and power plant	<input type="text"/>	%

Survey Contact

Contact	Erin Dukart	Submit Date	19-MAR-18
Title	Environmental Compliance Coordinator		
Address	1717 E. Interstate Avenue		
City/State/Zip	Bismarck	ND	58503
Email	edukart@bepc.com	Phone	(701) 557-5557 Fax

Supervisor of Contact Person for Survey

Contact	Joseph Leingang		
Title	Director of Fuels		
Address	1717 E. Interstate Avenue		
City/State/Zip	Bismarck	ND	58503
Email	jleingang@bepc.com	Phone	(701) 557-5648 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

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).

Report all generation in **megawatthours (MWh)** rounded to a whole number.

- | | |
|--------------------------------|---|
| (1) Gross Generation (Annual) | (4) Station Use |
| (2) Other Incoming Electricity | (5) Direct Use |
| | (6) Total Facility Use (4 + 5) |
| | (7) Retail Sales to Ultimate Customers |
| | (8) Sales for Resale (MWh) |
| | (9) Provided Tolling Agreement (MWh) |
| | (10) Other Outgoing Electricity |
| (3) Total Sources (1 + 2) | (11) Total Disposition (6 + 7 + 8 + 9 + 10) |

Total Sources must equal Total Disposition (3 = 11)

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.

Types of Other Incoming Electricity
List all of the types of incoming electricity included in (2)
Other Incoming Electricity

Types of Other Outgoing Electricity
List all of the types of outgoing electricity in item (10)
Other Outgoing Electricity

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

Supplemental EIA923 Power Plant Operations Report
Year: **2017** Plant: **6469** **Antelope Valley**

Form Approval
OMB No. 1905-0129
Approval Expires 03/31/2020

SCHEDULE 7. PART A. ANNUAL REVENUES FROM SALES FOR RESALE TOAL

Complete Schedule 7, Part A, only if a positive value was entered on Schedule 6, Item (8): "Sales for Resale."

Sales for Resale are energy supplied to electric utilities, cooperatives, municipalities, federal and state electric agencies, power marketers, or other entities, for resale to end-use consumers.

Report in thousand dollars. For example \$1,987,234 should be entered as 1,987

Annual Revenues from Sales for Resale (in thousand dollars)

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

Supplemental EIA923 Power Plant Operations Report
Year: **2017** Plant: **6469** **Antelope Valley**

Form Approval
OMB No. 1905-0129
Approval Expires 03/31/2020

SCHEDULE 7. PART B. ANNUAL RETAIL SALES, REVENUES AND NUMBER OF CUSTOMERS FROM RETAIL SALES

Report by state and end-use customer sectors (Residential, Commercial, industrial and Transportation).

Complete an individual Schedule 7, Part B, for each state where customers are located, only if a positive value was entered on Schedule 6, Item (7), "Retail Sales to Ultimate Customers."

Annual Retail Sales, Revenue, and Number of Customers:

- Retail sales are sold directly to an end-use customer (i.e., the energy is consumed by the customer, onsite, and is not resold to other customers).
- Enter annual retail sales, revenue, and number of customers for each state where customer(s) are located.
- Report Annual Retail Sales in megawatthours (Mwh), by sector.
- Report Annual Revenue in thousand dollars, by sector.
- Report Number of Customers, by sector.

State					
Items	Residential	Commercial	Industrial	Transportation	Total
Retail Sales (Mwh)					
Revenue (\$ 000's)					
Number of Customers					

SCHEDULE 8. PART B. FINANCIAL INFORMATION RELATED TO COMBUSTION BY-PRODUCTS

Complete an individual Schedule 8, Part B, annually, for each organically fueled thermoelectric power plant with a total steam turbine capacity greater than, or equal to, 100 megawatts.

- Data reported in Schedule 8, Part B must correspond to the combustion by-product data reported on Schedule 8, Part A.
- If actual data are not available, provide an estimate value.
- Report all values in thousand dollars, to the nearest thousand.

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	2,264	869	20,443	0	1,506	25,082
Disposal						
Other						

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	167	0	75	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	9	0	0	0	0	9

SCHEDULE 8. PART C. AIR EMISSIONS CONTROL INFORMATION

Report electricity generation related operational emissions data for sulfur dioxide (SO2), nitrogen oxides (NO2), particulate matter, mercury, and acid gas.

Annual Operations

Environmental Equipment and/or Technology Type							NOx Emission Rate (lbs/MMBtu)		Particulate Matter Control				Sulfur Dioxide Control				Mercury Control		Acid Gas Control	
Types	PM Control ID	SO2 CONTROL ID	NOX Control ID	Mercury Control	Status	Hours in Service	Entire Year	May through September	Emission Rate (0.01 lb/MMBtu)	Removal Efficiency Rate at AOF	Tested Efficiency Particulate Removal (at 100% Load)	Test Date MM-YYYY	Removal Efficiency Rate at AOF	Removal Tested Efficiency (at 100% Load)	Test Date MM-YYY	Quantity of FGD Sorbent Used (nearest 0.1 thousand tons)	FGD Unit Electrical Energy Consumption	Removal Efficiency (nearest 0.1% by weight)	Emission Rate (0.01 lbs / Tbtu)	Removal Efficiency (nearest 0.1% by weight)
LN			B1		OP	7328	.1089	.103												
OT				1	OP	7328													2.66	
OV			B1		OP	7328	.1089	.103												
LN			B2		OP	8506	.1081	.102												
OT				2	OP	8506													2.80	
OV			B2		OP	8506	.1089	.103												
BR	BH1			1	OP	7328			.0035	99.9	99.9	08-1983								
BR	BH2			2	OP	8506			.0032	99.9	99.9	08-1986								
SD		FGD1		1	OP	7328								63.9	09-1983	46.3	12093			
SD		FGD2		2	OP	8506								85.8	08-1986	52.9	14036			

SCHEDULE 8. PART C. AIR EMISSIONS CONTROL INFORMATION

Annual Operations																							
Environmental Equipment and/or Technology Type					NOx Emission Rate (lbs/MMBtu)		Particulate Matter Control					Sulfur Dioxide Control					Mercury Control	Acid Gas Control					
Types	PM Control ID	SO2 CONTROL ID	NOX Control ID	Mercury Control	Status	Hours in Service	Entire Year	May through September	Emission Rate (0.01 lb/MMBtu)	Removal Efficiency Rate at AOF	Tested Efficiency Particulate Removal (at 100% Load)	Test Date MM-YYYY	Removal Efficiency Rate at AOF	Removal Tested Efficiency (at 100% Load)	Test Date MM-YYY	Quantity of FGD Sorbent Used (nearest 0.1 thousand tons)	FGD Unit Electrical Energy Consumption	Removal Efficiency (nearest 0.1% by weight)	Emission Rate (0.01 lbs / Tbtu)	Removal Efficiency (nearest 0.1% by weight)			
Flue Gas Desulfurization Unit ID					Feed Materials and Chemicals		FGD Operation and Maintenance Expenditures During Year, Excluding Electricity (Thousand Dollars)					Maintenance, Material and All Other Costs					Total						
							Land and Supervision					Waste Disposal											
FGD1					\$4,541		\$2,421					\$564					\$1,621		\$9,147				
FGD2					\$5,348		\$2,852					\$664					\$2,431					\$11,295	

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

Complete an individual Schedule 8, Part D for each thermoelectric power plant (organically fueled, nuclear and combined cycle) with a total steam capacity greater than, or equal to, 100 megawatts.

- Complete a separate schedule for each reporting month.
- Complete a separate row for each cooling system.
- If actual data are not available, provided an estimated value.
- If the source of cooling water is a well or municipal water system, do not complete the Cooling Water Temperature sections.

Cooling System ID	Cooling System Type	Cooling System Status	Service Per month	Annual Amt of Chlorine in added to Cooling Water (1000 lbs)	Average Monthly Rate of Cooling Water (to nearest 0.1 gallons per minute)				Method of Measure	Cooling Water Temperature (degrees Fahrenheit)					Volume Cooling Water (to nearest 0.001 million gallons per month)				
					Div	Withdrawal	Discharge	Consumption		Avg at Intake	Max at Intake	Avg at Discharge	Max at Discharge	Method of Measure	Div	Withdrawal	Discharge	Consumption	
Report Month 1																			
CC1	RF	OP	728	3.536	3237.2	3237.2	0	3237.2	2	32					7	144.516	144.516	0	144.516
Report Month 2																			
CC1	RF	OP	672	3.07	3003.9	3003.9	0	3003.9	2	32					7	135.451	125.451		125.451
Report Month 3																			
CC1	RF	OP	743	3.428	3138.3	3138.3	0	3138.3	2	40					7	140.102	140.102	0	140.102
Report Month 4																			
CC1	RF	OP	333	1.824	1725.9	1725.9	0	1725.9	2	50					7	74.562	74.562	0	74.562
Report Month 5																			
CC1	RF	OP	0	0	0	0	0	0	2	38					7	0	0	0	0
Report Month 6																			
CC1	RF	OP	511	2.661	2517.5	2517.5	0	2517.5	2	66					7	108.761	108.761	0	108.761

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

Complete an individual Schedule 8, Part D for each thermoelectric power plant (organically fueled, nuclear and combined cycle) with a total steam capacity greater than, or equal to, 100 megawatts.

- Complete a separate schedule for each reporting month.
- Complete a separate row for each cooling system.
- If actual data are not available, provided an estimated value.
- If the source of cooling water is a well or municipal water system, do not complete the Cooling Water Temperature sections.

Cooling System ID	Cooling System Type	Cooling System Status	Annual Amt of Hours Chlorine in added to Service Cooling Water (1000 lbs)	Average Monthly Rate of Cooling Water (to nearest 0.1 gallons per minute)				Cooling Water Temperature (degrees Fahrenheit)					Volume Cooling Water (to nearest 0.001 million gallons per month)						
				Div	Withdrawal	Discharge	Consumption	Method of Measure	Avg at Intake	Max at Intake	Avg at Discharge	Max at Discharge	Method of Measure	Div	Withdrawal	Discharge	Consumption		
Report Month 7																			
CC1	RF	OP	741	4.124	3775.7	3775.7	0	3775.7	2	72					7	168.556	168.556	0	168.556
Report Month 8																			
CC1	RF	OP	739	3.797	3201.6	3201.6	0	3201.6	2	71					7	142.929	142.929	0	142.929
Report Month 9																			
CC1	RF	OP	720	3.357	3176	3176	0	3176	2	61					7	137.21	137.21	0	137.21
Report Month 10																			
CC1	RF	OP	744	3.184	2914.5	2914.5	0	2914.5	2	54					7	130.113	130.113	0	130.113
Report Month 11																			
CC1	RF	OP	659	2.803	2651.8	2651.8	0	2651.8	2	41					7	114.565	114.565	0	114.565
Report Month 12																			
CC1	RF	OP	683	2.996	2743	2743	0	2743	2	32					7	122.455	122.455	0	122.455

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

Complete an individual Schedule 8, Part D for each thermoelectric power plant (organically fueled, nuclear and combined cycle) with a total steam capacity greater than, or equal to, 100 megawatts.

- Complete a separate schedule for each reporting month.
- Complete a separate row for each cooling system.
- If actual data are not available, provided an estimated value.
- If the source of cooling water is a well or municipal water system, do not complete the Cooling Water Temperature sections.

Cooling System ID	Cooling System Type	Cooling System Status	Annual Amt of Hours Chlorine in added to Service Cooling Water (1000 lbs)	Average Monthly Rate of Cooling Water (to nearest 0.1 gallons per minute)				Method of Measure	Cooling Water Temperature (degrees Fahrenheit)					Volume Cooling Water (to nearest 0.001 million gallons per month)					
				Div	Withdrawal	Discharge	Consumption		Avg at Intake	Max at Intake	Avg at Discharge	Max at Discharge	Method of Measure	Div	Withdrawal	Discharge	Consumption		
Report Month 1																			
CC2	RF	OP	744	3.454	3293.3	3293.3	0	3293.3	2	32					7	146.898	146.898	0	146.898
Report Month 2																			
CC2	RF	OP	671	2.905	2961.3	2961.3	0	2961.3	2	32					7	123.568	123.568		123.568
Report Month 3																			
CC2	RF	OP	743	3.284	3131.3	3131.3	0	3131.3	2	40					7	139.673	139.673	0	139.673
Report Month 4																			
CC2	RF	OP	720	3.683	3629.5	3629.5	0	3629.5	2	50					7	156.674	156.674	0	156.674
Report Month 5																			
CC2	RF	OP	680	3.924	3742.3	3742.3	0	3742.3	2	38					7	166.927	166.927	0	166.927
Report Month 6																			
CC2	RF	OP	690	3.315	3266.3	3266.3	0	3266.3	2	66					7	140.998	140.998	0	140.998

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

Complete an individual Schedule 8, Part D for each thermoelectric power plant (organically fueled, nuclear and combined cycle) with a total steam capacity greater than, or equal to, 100 megawatts.

- Complete a separate schedule for each reporting month.
- Complete a separate row for each cooling system.
- If actual data are not available, provided an estimated value.
- If the source of cooling water is a well or municipal water system, do not complete the Cooling Water Temperature sections.

Cooling System ID	Cooling System Type	Cooling System Status	Hours Service Per month	Annual Amt of Chlorine in added to Cooling Water (1000 lbs)	Average Monthly Rate of Cooling Water (to nearest 0.1 gallons per minute)				Method of Measure	Cooling Water Temperature (degrees Fahrenheit)					Volume Cooling Water (to nearest 0.001 million gallons per month)				
					Div	Withdrawal	Discharge	Consumption		Avg at Intake	Max at Intake	Avg at Discharge	Max at Discharge	Method of Measure	Div	Withdrawal	Discharge	Consumption	
Report Month 7																			
CC2	RF	OP	696	3.677	3506.3	3506.3	0	3506.3	2	72					7	156.401	156.401	0	156.401
Report Month 8																			
CC2	RF	OP	720	3.769	3594	3594	0	3594	2	71					7	160.314	160.314	0	160.314
Report Month 9																			
CC2	RF	OP	663	3.089	3044.2	3044.2	0	3044.2	2	61					7	131.409	131.409	0	131.409
Report Month 10																			
CC2	RF	OP	744	3.151	3004.4	3004.4	0	3004.4	2	54					7	134.014	134.014	0	134.014
Report Month 11																			
CC2	RF	OP	692	2.896	2854.1	2854.1	0	2854.1	2	41					7	123.204	123.204	0	123.204
Report Month 12																			
CC2	RF	OP	684	2.901	2766.3	2766.3	0	2766.3	2	32					7	122.392	123.392	0	123.392

SCHEDULE 9. COMMENTS
 (Instructions for SCHEDULE 9. are on page 20.)

Schedule	Part	Item	Comments
8	B	1-6	Cost accounting granularity does not go any finer than this level of aggregation; so Collection, Disposal, and Other are aggregated in "Collection". Please direct questions on this matter to jleingang@bepc.com
8	C	OT	Liquid injection into the scrubber.
8	D	F	Cooling Water Temperature Method of Measurement is USGA Data from Lake for all

Generator Id	Retirement		Generator Retirement Dates
	Month	Year	Comments
	Changes in Ownership (Provide name of purchaser and date sold.)		

ERRORS

Purchase Type	Fuel	Schedule	Prime Mover	Equipment ID	Rpt Month	Supplier	Error Number & Description	Ranges	Override Comment
C	LIG	2A				DAKOTA COAL (FREEDOM MINE)	218 Commodity Cost was reported as Zero. Commodity Cost is the difference between the Total Cost and Transportation Costs. If these costs cannot be reported separately, please leave commodity cost blank and enter a detailed explanation in the override comment for analyst review.		Which is what I did.
C	NG	2A				DAKOTA GASIFICATION COMPANY	218 Commodity Cost was reported as Zero. Commodity Cost is the difference between the Total Cost and Transportation Costs. If these costs cannot be reported separately, please leave commodity cost blank and enter a detailed explanation in the override comment for analyst review.		Which is what I did.
	NG	4			0		1400 The difference between consumed, received and stocked fuel and the reported ending stocks does not balance for this fuel type. A comment explaining the imbalance of this fuel type is missing on Schedule 4A.		Corrected
		8A					808 You have entered a cost in O&M Expenditures for FGD on Schedule 8B (Part 3), but have not entered a positive quantity of FGD Gypsum or By-products in any column on Schedule 8A. Please enter the quantity of FGD byproduct or FGD Gypsum associated with the costs in Schedule 8B.		FGD quantity is included in the fly ash quantity.
		8C		/SD			890 Acid Gas Removal Efficiency cannot be null if hours in service are provided. Please review reported data.		This equipment is intended for SO2 control. While it does removed acid gases, that is not its intended function, so removal efficiency is unknown.
		8D					864 The code for "Other" was selected for the 'Measured or Estimated' Water Temperature. Specify the method in an override comment.		Cooling Water Temperature Method of Measurement is USGA Data from Lake for all. This was reported in Schedule 9 as indicated by the directions.

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

Is this a regulated utility plant Yes No
Is this a combined heat and power plant Yes No

Enter the total plant efficiency of the combined heat and power plant %

Survey Contact

Contact Erin Dukart Submit Date 23-MAY-17
Title Environmental Compliance Coordinator
Address 1717 E. Interstate Avenue
City/State/Zip Bismarck ND 58503
Email edukart@bepc.com Phone (701) 557-5557 Fax

Supervisor of Contact Person for Survey

Contact Joseph Leingang
Title Director of Fuels
Address 1717 E. Interstate Avenue
City/State/Zip Bismarck ND 58503
Email jleingang@bepc.com Phone (701) 557-5648 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

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).
Report all generation in **megawatthours (MWh)** rounded to a whole number.

- | | |
|--------------------------------|---|
| (1) Gross Generation (Annual) | (4) Station Use |
| (2) Other Incoming Electricity | (5) Direct Use |
| | (6) Total Facility Use (4 + 5) |
| | (7) Retail Sales to Ultimate Customers |
| | (8) Sales for Resale (MWh) |
| | (9) Provided Tolling Agreement (MWh) |
| | (10) Other Outgoing Electricity |
| (3) Total Sources (1 + 2) | (11) Total Disposition (6 + 7 + 8 + 9 + 10) |

Total Sources must equal Total Disposition (3 = 11)

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.

Types of Other Incoming Electricity
List all of the types of incoming electricity included in (2)
Other Incoming Electricity

Types of Other Outgoing Electricity
List all of the types of outgoing electricity in item (10)
Other Outgoing Electricity

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

Supplemental EIA923 Power Plant Operations Report
Year: **2016** Plant: **2817** **Leland Olds**

Form Approval
OMB No. 1905-0129
Approval Expires 03/31/2020

SCHEDULE 7. PART A. ANNUAL REVENUES FROM SALES FOR RESALE TOAL

Complete Schedule 7, Part A, only if a positive value was entered on Schedule 6, Item (8): "Sales for Resale."

Sales for Resale are energy supplied to electric utilities, cooperatives, municipalities, federal and state electric agencies, power marketers, or other entities, for resale to end-use consumers.

Report in thousand dollars. For example \$1,987,234 should be entered as 1,987

Annual Revenues from Sales for Resale (in thousand dollars)

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

Supplemental EIA923 Power Plant Operations Report
Year: **2016** Plant: **2817** **Leland Olds**

Form Approval
OMB No. 1905-0129
Approval Expires 03/31/2020

SCHEDULE 7. PART B. ANNUAL RETAIL SALES, REVENUES AND NUMBER OF CUSTOMERS FROM RETAIL SALES

Report by state and end-use customer sectors (Residential, Commercial, industrial and Transportation).

Complete an individual Schedule 7, Part B, for each state where customers are located, only if a positive value was entered on Schedule 6, Item (7), "Retail Sales to Ultimate Customers."

Annual Retail Sales, Revenue, and Number of Customers:

- Retail sales are sold directly to an end-use customer (i.e., the energy is consumed by the customer, onsite, and is not resold to other customers).
- Enter annual retail sales, revenue, and number of customers for each state where customer(s) are located.
- Report Annual Retail Sales in megawatthours (Mwh), by sector.
- Report Annual Revenue in thousand dollars, by sector.
- Report Number of Customers, by sector.

State					
Items	Residential	Commercial	Industrial	Transportation	Total
Retail Sales (Mwh)					
Revenue (\$ 000's)					
Number of Customers					

SCHEDULE 8. PART B. FINANCIAL INFORMATION RELATED TO COMBUSTION BY-PRODUCTS

Complete an individual Schedule 8, Part B, annually, for each organically fueled thermoelectric power plant with a total steam turbine capacity greater than, or equal to, 100 megawatts.

- Data reported in Schedule 8, Part B must correspond to the combustion by-product data reported on Schedule 8, Part A.
- If actual data are not available, provide an estimate value.
- Report all values in thousand dollars, to the nearest thousand.

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	1,041	812	4,973	0	0	6,826
Disposal						
Other						

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	10,970	0	4,960	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	226	97	0	0	0	323

Supplemental EIA923 Power Plant Operations Report

Year: 2016 Plant: 2817 Leland Olds

SCHEDULE 8. PART C. AIR EMISSIONS CONTROL INFORMATION

Report electricity generation related operational emissions data for sulfur dioxide (SO2), nitrogen oxides (NO2), particulate matter, mercury, and acid gas.

Environmental Equipment and/or Technology Type							NOx Emission Rate (lbs/MMBtu)		Particulate Matter Control				Sulfur Dioxide Control				Mercury Control		Acid Gas Control		
Types	PM Control ID	SO2 CONTROL ID	NOX CONTROL ID	Mercury Control	Status	Hours in Service	Entire Year	May through September	Emission Rate (0.01 lb/MMBtu)	Removal Efficiency Rate at AOF	Tested Efficiency Particulate Removal (at 100% Load)	Test Date MM-YYYY	Removal Efficiency Rate at AOF	Removal Tested Efficiency (at 100% Load)	Test Date MM-YYY	Quantity of FGD Sorbent Used (nearest 0.1 thousand tons)	FGD Unit Electrical Energy Consumption	Removal Efficiency (nearest 0.1% by weight)	Emission Rate (0.01 lbs / Tbtu)	Removal Efficiency (nearest 0.1% by weight)	
LN			1		OP	8373	.25	.23													
OV			1		OP	8373	.25	.23													
OV			2		OP	8180	.37	.35													
ACI				1	OP	8373														2.00	
ACI				2	OP	8180														2.30	
EK	1			1B	OP	8373			.0045	79.8	99.8	12-1974								2.00	
EK	2			2B	OP	8180			.0057	80.6	99.5	12-1976								2.30	
SP		1		1C	OP	8373							78.2	97.7	08-2013	35.3	40366			2.00	
SP		2		2C	OP	8180							79.9	98.7	01-2013	68.6	76790			2.30	

SCHEDULE 8. PART C. AIR EMISSIONS CONTROL INFORMATION

Annual Operations																						
Environmental Equipment and/or Technology Type							NOx Emission Rate (lbs/MMBtu)		Particulate Matter Control				Sulfur Dioxide Control					Mercury Control		Acid Gas Control		
Types	PM Control ID	SO2 CONTROL ID	NOX Control ID	Mercury Control	Status	Hours in Service	Entire Year	May through September	Emission Rate (0.01 lb/MMBtu)	Removal Efficiency Rate at AOF	Tested Efficiency Particulate Removal (at 100% Load)	Test Date MM-YYYY	Removal Efficiency Rate at AOF	Removal Tested Efficiency (at 100% Load)	Test Date MM-YYY	Quantity of FGD Sorbent Used (nearest 0.1 thousand tons)	FGD Unit Electrical Energy Consumption	Removal Efficiency	Emission Rate (nearest 0.01 lbs/Tbtu)	Removal Efficiency		
Flue Gas Desulfurization Unit ID					Feed Materials and Chemicals		FGD Operation and Maintenance Expenditures During Year, Excluding Electricity (Thousand Dollars)										Maintenance, Material and All Other Costs					Total
							Land and Supervision					Waste Disposal										
1					\$1,070		\$161					\$49					\$369					\$1,649
2					\$2,128		\$358					\$98					\$740					\$3,324

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

Complete an individual Schedule 8, Part D for each thermoelectric power plant (organically fueled, nuclear and combined cycle) with a total steam capacity greater than, or equal to, 100 megawatts.

- Complete a separate schedule for each reporting month.
- Complete a separate row for each cooling system.
- If actual data are not available, provided an estimated value.
- If the source of cooling water is a well or municipal water system, do not complete the Cooling Water Temperature sections.

Cooling System ID	Cooling System Type	Cooling System Status	Annual Amt of Hours Chlorine in added to Service Per Cooling Water (1000 lbs)	Average Monthly Rate of Cooling Water (to nearest 0.1 gallons per minute)				Cooling Water Temperature (degrees Fahrenheit)					Volume Cooling Water (to nearest 0.001 million gallons per month)					
				Div	Withdrawal	Discharge	Consumption	Method of Measure	Avg at Intake	Max at Intake	Avg at Discharg	Max at Discharg	Method of Measure	Div	Withdrawal	Discharge	Consumption	
Report Month 1																		
1	ON	OP	744	0		71479	71479	0	4	42	50	53	72	1		3190.822	3190.822	0
Report Month 2																		
1	ON	OP	696	0		71714	71714	0	4	42	49	55	68	1		2994.757	2994.757	0
Report Month 3																		
1	ON	OP	743	0		71740	71740	0	4	40	44	59	71	1		3198.175	3198.175	0
Report Month 4																		
1	ON	OP	720	0		71673	71673	0	4	42	48	63	77	1		3096.285	3096.285	0
Report Month 5																		
1	ON	OP	744	0		71644	71644	0	4	50	54	73	83	1		3198.193	3198.193	0
Report Month 6																		
1	ON	OP	720	0		71673	71673	0	4	58	64	83	92	1		3096.289	3096.289	0

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

Complete an individual Schedule 8, Part D for each thermoelectric power plant (organically fueled, nuclear and combined cycle) with a total steam capacity greater than, or equal to, 100 megawatts.

- Complete a separate schedule for each reporting month.
- Complete a separate row for each cooling system.
- If actual data are not available, provided an estimated value.
- If the source of cooling water is a well or municipal water system, do not complete the Cooling Water Temperature sections.

Cooling System ID	Cooling System Type	Cooling System Status	Hours Per month	Annual Amt of Chlorine in added to Service Water (1000 lbs)	Average Monthly Rate of Cooling Water (to nearest 0.1 gallons per minute)				Cooling Water Temperature (degrees Fahrenheit)					Volume Cooling Water (to nearest 0.001 million gallons per month)				
					Div	Withdrawal	Discharge	Consumption	Method of Measure	Avg at Intake	Max at Intake	Avg at Discharge	Max at Discharge	Method of Measure	Div	Withdrawal	Discharge	Consumption
Report Month 7																		
1	ON	OP	744	0		71656	71656	0	4	62	67	85	96	1		3198.738	3198.738	0
Report Month 8																		
1	ON	OP	744	0		71631	71631	0	4	65	70	87	98	1		3197.608	137.608	0
Report Month 9																		
1	ON	OP	720	0		70861	70861	0	4	64	68	87	97	1		3061.204	3061.204	0
Report Month 10																		
1	ON	OP	744	0		61273	61273	0	4	60	67	79	91	1		2735.213	2735.213	0
Report Month 11																		
1	ON	OP	720	0		66866	66866	0	4	54	59	73	84	1		2862.635	2892.635	0
Report Month 12																		
1	ON	OP	744	0		71475	71475	0	4	42	51	61	77	1		3190.654	3190.654	0

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

Complete an individual Schedule 8, Part D for each thermoelectric power plant (organically fueled, nuclear and combined cycle) with a total steam capacity greater than, or equal to, 100 megawatts.

- Complete a separate schedule for each reporting month.
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- If actual data are not available, provided an estimated value.
- If the source of cooling water is a well or municipal water system, do not complete the Cooling Water Temperature sections.

Cooling System ID	Cooling System Type	Cooling System Status	Service Per monthe	Annual Amt of Chlorine in added to Cooling Water (1000 lbs)	Average Monthly Rate of Cooling Water (to nearest 0.1 gallons per minute)				Cooling Water Temperature (degrees Fahrenheit)					Volume Cooling Water (to nearest 0.001 million gallons per month)				
					Div	Withdrawal	Discharge	Consumption	Method of Measure	Avg at Intake	Max at Intake	Avg at Discharg	Max at Discharg	Method of Measure	Div	Withdrawal	Discharge	Consumption
Report Month 1																		
2	ON	OP	744	0		149112	149112	0	4	42	50	66	94	1		6656.372	6656.372	0
Report Month 2																		
2	ON	OP	696	0		129125	129125	0	4	42	49	66	95	1		5392.274	5392.274	0
Report Month 3																		
2	ON	OP	743	0		93489	93489	0	4	40	44	69	97	1		4167.756	4167.756	0
Report Month 4																		
2	ON	OP	720	0		149347	149347	0	4	42	48	69	83	1		6451.769	6451.769	0
Report Month 5																		
2	ON	OP	744	0		149288	149288	0	4	50	54	76	85	1		6664.226	6664.226	0
Report Month 6																		
2	ON	OP	720	0		149237	149237	0	4	58	64	79	97	1		6447.053	6447.053	0

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

Complete an individual Schedule 8, Part D for each thermoelectric power plant (organically fueled, nuclear and combined cycle) with a total steam capacity greater than, or equal to, 100 megawatts.

- Complete a separate schedule for each reporting month.
- Complete a separate row for each cooling system.
- If actual data are not available, provided an estimated value.
- If the source of cooling water is a well or municipal water system, do not complete the Cooling Water Temperature sections.

Cooling System ID	Cooling System Type	Cooling System Status	Hours Per month	Annual Amt of Chlorine in added to Cooling Water (1000 lbs)	Average Monthly Rate of Cooling Water (to nearest 0.1 gallons per minute)				Cooling Water Temperature (degrees Fahrenheit)					Volume Cooling Water (to nearest 0.001 million gallons per month)				
					Div	Withdrawal	Discharge	Consumption	Method of Measure	Avg at Intake	Max at Intake	Avg at Discharge	Max at Discharge	Method of Measure	Div	Withdrawal	Discharge	Consumption
Report Month 7																		
2	ON	OP	744	0		149313	149313	0	4	62	67	85	98	1		6665.316	6665.316	0
Report Month 8																		
2	ON	OP	744	0		149262	149262	0	4	65	70	91	98	1		6663.055	6663.055	0
Report Month 9																		
2	ON	OP	720	0		149316	149316	0	4	64	68	86	97	1		6450.441	6450.441	0
Report Month 10																		
2	ON	OP	744	0		149300	149300	0	4	60	67	86	97	1		664.762	664.762	0
Report Month 11																		
2	ON	OP	720	0		136755	136755	0	4	54	59	71	89	1		5916.031	5916.031	0
Report Month 12																		
2	ON	OP	744	0		148824	148824	0	4	42	51	68	82	1		6643.483	6643.483	0

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

Supplemental EIA923 Power Plant Operations Report
Year: **2016** Plant: **2817** **Leland Olds**

Form Approval
OMB No. 1905-0129
Approval Expires 03/31/2020

SCHEDULE 9. COMMENTS
(Instructions for SCHEDULE 9. are on page 20.)

Schedule	Part	Item	Comments
8	B	1-6	Cost Accounting granularity does not go finer than this level of aggregation, so Collection, Disposal and Other are aggregated in "Collection". Direct questions on this matter to jleingang@bepc.com

Generator Id	Retirement		Generator Retirement Dates
	Month	Year	Comments
	Changes in Ownership (Provide name of purchaser and date sold.)		

ERRORS

Purchase Type	Fuel	Schedule	Prime Mover	Equipment ID	Rpt Month	Supplier	Error Number & Description	Ranges	Override Comment
		8B					835 Sales of fly and bottom ash (Line 1, 2, 3, 4, and 5) were reported on Schedule 8, Part A. Please enter the revenue (Part 13) in units of thousand dollars from those sales on Schedule 8B, if applicable. If the fly and bottom ash sold were not sold intermingled, please comment.		All appropriate sales data has been entered.
		8B					837 Sales of FGD By-products (Lines 6 and 7) were reported on Schedule 8, Part A. Please enter the revenue (Part 14) in units of thousand dollars from those sales on Schedule 8B. Example: enter revenue of 5 million dollars as 5,000, not 5,000,000.		All revenue data has been entered.
		8C		2/SP			851 The Removal Efficiency tested at 100% load for sulfur dioxide is outside the expected range of 50%-99%. If correct, enter a comment to explain data out of typical range.		Low Loads

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

Is this a regulated utility plant
Is this a combined heat and power plant

Yes No

Yes No

Enter the total plant efficiency of the combined heat and power plant

%

Survey Contact

Contact Erin Dukart
Title Environmental Compliance Coordinator
Address 1717 E. Interstate Avenue

Submit Date 19-MAR-18

City/State/Zip Bismarck
Email edukart@bepc.com

ND 58503
Phone (701) 557-5557 Fax

Supervisor of Contact Person for Survey

Contact Joseph Leingang
Title Director of Fuels
Address 1717 E. Interstate Avenue

City/State/Zip Bismarck
Email jleingang@bepc.com

ND 58503
Phone (701) 557-5648 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

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).
Report all generation in **megawatthours (MWh)** rounded to a whole number.

- | | |
|--------------------------------|---|
| (1) Gross Generation (Annual) | (4) Station Use |
| (2) Other Incoming Electricity | (5) Direct Use |
| | (6) Total Facility Use (4 + 5) |
| | (7) Retail Sales to Ultimate Customers |
| | (8) Sales for Resale (MWh) |
| | (9) Provided Tolling Agreement (MWh) |
| | (10) Other Outgoing Electricity |
| (3) Total Sources (1 + 2) | (11) Total Disposition (6 + 7 + 8 + 9 + 10) |

Total Sources must equal Total Disposition (3 = 11)

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.

Types of Other Incoming Electricity
List all of the types of incoming electricity included in (2)
Other Incoming Electricity

Types of Other Outgoing Electricity
List all of the types of outgoing electricity in item (10)
Other Outgoing Electricity

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

Supplemental EIA923 Power Plant Operations Report
Year: **2017** Plant: **2817** **Leland Olds**

Form Approval
OMB No. 1905-0129
Approval Expires 03/31/2020

SCHEDULE 7. PART A. ANNUAL REVENUES FROM SALES FOR RESALE TOAL

Complete Schedule 7, Part A, only if a positive value was entered on Schedule 6, Item (8): "Sales for Resale."

Sales for Resale are energy supplied to electric utilities, cooperatives, municipalities, federal and state electric agencies, power marketers, or other entities, for resale to end-use consumers.

Report in thousand dollars. For example \$1,987,234 should be entered as 1,987

Annual Revenues from Sales for Resale (in thousand dollars)

SCHEDULE 7. PART B. ANNUAL RETAIL SALES, REVENUES AND NUMBER OF CUSTOMERS FROM RETAIL SALES

Report by state and end-use customer sectors (Residential, Commercial, industrial and Transportation).

Complete an individual Schedule 7, Part B, for each state where customers are located, only if a positive value was entered on Schedule 6, Item (7), "Retail Sales to Ultimate Customers."

Annual Retail Sales, Revenue, and Number of Customers:

- Retail sales are sold directly to an end-use customer (i.e., the energy is consumed by the customer, onsite, and is not resold to other customers).
- Enter annual retail sales, revenue, and number of customers for each state where customer(s) are located.
- Report Annual Retail Sales in megawatthours (Mwh), by sector.
- Report Annual Revenue in thousand dollars, by sector.
- Report Number of Customers, by sector.

State					
Items	Residential	Commercial	Industrial	Transportation	Total
Retail Sales (Mwh)					
Revenue (\$ 000's)					
Number of Customers					

SCHEDULE 8. PART B. FINANCIAL INFORMATION RELATED TO COMBUSTION BY-PRODUCTS

Complete an individual Schedule 8, Part B, annually, for each organically fueled thermoelectric power plant with a total steam turbine capacity greater than, or equal to, 100 megawatts.

- Data reported in Schedule 8, Part B must correspond to the combustion by-product data reported on Schedule 8, Part A.

- If actual data are not available, provide an estimate value.

- Report all values in thousand dollars, to the nearest thousand.

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	1,713	1,490	6,392	0	78	9,673
Disposal						
Other						

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	26	82	19,992	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	247	3	0	0	0	250

SCHEDULE 8. PART C. AIR EMISSIONS CONTROL INFORMATION

Report electricity generation related operational emissions data for sulfur dioxide (SO2), nitrogen oxides (NO2), particulate matter, mercury, and acid gas.

Annual Operations

Environmental Equipment and/or Technology Type					Status	Hours in Service	NOx Emission Rate (lbs/MMBtu)		Particulate Matter Control				Sulfur Dioxide Control					Mercury Control		Acid Gas Control
Types	PM Control ID	SO2 CONTROL ID	NOX Control ID	Mercury Control			Entire Year	May through September	Emission Rate (0.01 lb/MMBtu)	Removal Efficiency Rate at AOF	Tested Efficiency Particulate Removal (at 100% Load)	Test Date MM-YYYY	Removal Efficiency Rate at AOF	Removal Tested Efficiency (at 100% Load)	Test Date MM-YYY	Quantity of FGD Sorbent Used (nearest 0.1 thousand tons)	FGD Unit Electrical Energy Consumption	Removal Efficiency (nearest 0.1% by weight)	Emission Rate (0.01 lbs / Tbtu)	Removal Efficiency (nearest 0.1% by weight)
ACI				1	OP	6747												2.13		
LN			1		OP	6747	.1768	.1758												
OV			1		OP	6747	.1768	.1758												
ACI				2	OP	8109												1.96		
OV			2		OP	8109	.2934	.2938												
EK	1			1B	OP	6747		.008	99.8	99.8	12-1974									
EK	2			2B	OP	8109		.0083	99.5	99.5	12-1976									
SN			1		OP	4984	.1768	.1758												
SN			2		OP	6165	.2934	.2938												
SP		1		1C	OP	6747						97.3	97.7	08-2013	27	33933				

SCHEDULE 8. PART C. AIR EMISSIONS CONTROL INFORMATION

Annual Operations

Environmental Equipment and/or Technology Type					Status		NOx Emission Rate (lbs/MMBtu)		Particulate Matter Control				Sulfur Dioxide Control				Mercury Control	Acid Gas Control	
Types	PM Control ID	SO2 CONTROL ID	NOX Control ID	Mercury Control	Hours in Service	Entire Year	May through September	Emission Rate (0.01 lb/MMBtu)	Removal Efficiency Rate at AOF	Tested Efficiency Particulate Removal (at 100% Load)	Test Date MM-YYYY	Removal Efficiency Rate at AOF	Removal Tested Efficiency (at 100% Load)	Test Date MM-YYY	Quantity of FGD Sorbent Used (nearest 0.1 thousand tons)	FGD Unit Electrical Energy Consumption	Removal Efficiency (nearest 0.1% by weight)	Emission Rate (0.01 lbs / Tbtu)	Removal Efficiency (nearest 0.1% by weight)
SP		2		2C	OP	8109						97.2	98.7	01-2013	66.5	78068			

FGD Operation and Maintenance Expenditures During Year, Excluding Electricity (Thousand Dollars)

Flue Gas Desulfurization Unit ID	Feed Materials and Chemicals	Land and Supervision	Waste Disposal	Maintenance, Material and All Other Costs	Total
1	\$873	\$176	\$55	\$1,559	\$2,663
2	\$2,144	\$357	\$111	\$1,117	\$3,729

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

Complete an individual Schedule 8, Part D for each thermoelectric power plant (organically fueled, nuclear and combined cycle) with a total steam capacity greater than, or equal to, 100 megawatts.

- Complete a separate schedule for each reporting month.
- Complete a separate row for each cooling system.
- If actual data are not available, provided an estimated value.
- If the source of cooling water is a well or municipal water system, do not complete the Cooling Water Temperature sections.

Cooling System ID	Cooling System Type	Cooling System Status	Service Per monthe	Annual Amt of Chlorine in added to Cooling Water (1000 lbs)	Average Monthly Rate of Cooling Water (to nearest 0.1 gallons per minute)				Cooling Water Temperature (degrees Fahrenheit)					Volume Cooling Water (to nearest 0.001 million gallons per month)				
					Div	Withdrawal	Discharge	Consumption	Method of Measure	Avg at Intake	Max at Intake	Avg at Discharg	Max at Discharg	Method of Measure	Div	Withdrawal	Discharge	Consumption
Report Month 1																		
1	ON	OP	744	0		71656	71656	0	4	39	43	55	70	1		3198.746	3198.746	0
Report Month 2																		
1	ON	OP	672	0		71724	71724	0	4	40	46	58	73	1		2891.931	2891.931	0
Report Month 3																		
1	ON	OP	743	0		71695	71695	0	4	40	47	52	74	1		3196.153	3196.153	0
Report Month 4																		
1	ON	OP	720	0		71411	71411	0	4	41	46	61	76	1		3084.976	3084.976	0
Report Month 5																		
1	ON	OP	744	0		71659	71659	0	4	47	54	65	80	1		3198.84	3198.84	0
Report Month 6																		
1	ON	OP	720	0		71688	71688	0	4	56	62	77	90	1		3096.916	3096.916	0

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

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Cooling System ID	Cooling System Type	Cooling System Status	Annual Amt of Hours Chlorine in added to Service Cooling Water (1000 lbs)	Average Monthly Rate of Cooling Water (to nearest 0.1 gallons per minute)			Cooling Water Temperature (degrees Fahrenheit)					Volume Cooling Water (to nearest 0.001 million gallons per month)				
				Div	Withdrawal	Discharge Consumption	Method of Measure	Avg at Intake	Max at Intake	Avg at Discharg	Max at Discharg	Method of Measure	Div	Withdrawal	Discharge Consumption	
Report Month 7																
1	ON	OP	744	0	71634	71634	0	4	60	62	80	96	1	3197.732	3197.732	0
Report Month 8																
1	ON	OP	744	0	71574	71574	0	4	61	64	82	99	1	3195.058	3195.058	0
Report Month 9																
1	ON	OP	684	0	63575	63575	0	4	62	65	74	95	1	2608.176	2608.176	0
Report Month 10																
1	ON	OP	0	0	0	0	0	4	0	0	0	0	1	0	0	0
Report Month 11																
1	ON	OP	634	0	63195	63195	0	4	47	53	56	73	1	2404.256	2404.256	0
Report Month 12																
1	ON	OP	744	0	71702	71702	0	4	43	49	55	77	1	3200.77	3200.77	0

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

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- Complete a separate row for each cooling system.
- If actual data are not available, provided an estimated value.
- If the source of cooling water is a well or municipal water system, do not complete the Cooling Water Temperature sections.

Cooling System ID	Cooling System Type	Cooling System Status	Annual Amt of Hours Chlorine in added to Service Per Water (1000 lbs)	Average Monthly Rate of Cooling Water (to nearest 0.1 gallons per minute)				Cooling Water Temperature (degrees Fahrenheit)					Volume Cooling Water (to nearest 0.001 million gallons per month)					
				Div	Withdrawal	Discharge	Consumption	Method of Measure	Avg at Intake	Max at Intake	Avg at Discharg	Max at Discharg	Method of Measure	Div	Withdrawal	Discharge	Consumption	
Report Month 1																		
2	ON	OP	744	0		149313	149313	0	4	39	43	64	74	1		6665.332	6665.332	0
Report Month 2																		
2	ON	OP	672	0		149449	149449	0	4	40	46	56	77	1		6025.782	6025.782	0
Report Month 3																		
2	ON	OP	743	0		149390	149390	0	4	40	47	64	78	1		6659.786	6659.786	0
Report Month 4																		
2	ON	OP	720	0		149021	149021	0	4	41	46	64	75	1		6437.699	6437.699	0
Report Month 5																		
2	ON	OP	744	0		149317	149317	0	4	47	54	70	83	1		6665.521	6665.521	0
Report Month 6																		
2	ON	OP	720	0		148721	148721	0	4	56	62	74	89	1		6424.757	6424.757	0

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

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Cooling System ID	Cooling System Type	Cooling System Status	Annual Amt of Hours Chlorine in added to Service Cooling Water (1000 lbs)	Average Monthly Rate of Cooling Water (to nearest 0.1 gallons per minute)				Cooling Water Temperature (degrees Fahrenheit)					Volume Cooling Water (to nearest 0.001 million gallons per month)					
				Div	Withdrawal	Discharge	Consumption	Method of Measure	Avg at Intake	Max at Intake	Avg at Discharge	Max at Discharge	Method of Measure	Div	Withdrawal	Discharge	Consumption	
Report Month 7																		
2	ON	OP	744	0		149268.6	149268.6	0	4	60	62	84	91	1		6663.303	6663.303	0
Report Month 8																		
2	ON	OP	744	0		149333	149333	0	4	61	64	83	93	1		6666.235	6666.235	0
Report Month 9																		
2	ON	OP	720	0		149319	149319	0	4	62	65	89	95	1		6450.576	6450.576	0
Report Month 10																		
2	ON	OP	744	0		149542	149542	0	4	57	63	74	92	1		6675.573	6675.573	0
Report Month 11																		
2	ON	OP	720	0		148978	148978	0	4	47	53	71	87	1		6443.197	6443.197	0
Report Month 12																		
2	ON	OP	744	0		149126	149126	0	4	43	49	65	78	1		6657.004	6657.004	0

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

Supplemental EIA923 Power Plant Operations Report
Year: **2017** Plant: **2817** **Leland Olds**

Form Approval
OMB No. 1905-0129
Approval Expires 03/31/2020

SCHEDULE 9. COMMENTS
(Instructions for SCHEDULE 9. are on page 20.)

Schedule	Part	Item	Comments
8	B	1-6	Cost accounting granularity does not go any finer than this level of aggregation; so Collection, Disposal, and Other are aggregated in "Collection". Please direct questions on this matter to jleingang@bepc.com

Generator Id	Generator Retirement Dates		Comments
	Retirement Month	Retirement Year	
	Changes in Ownership (Provide name of purchaser and date sold.)		

ERRORS

Purchase Type	Fuel	Schedule	Prime Mover	Equipment ID	Rpt Month	Supplier	Error Number & Description	Ranges	Override Comment
		8B					835 Sales of fly and bottom ash (Line 1, 2, 3, 4, and 5) were reported on Schedule 8, Part A. Please enter the revenue (Part 13) in units of thousand dollars from those sales on Schedule 8B, if applicable. If the fly and bottom ash sold were not sold intermingled, please comment.		Fly and bottom ash sold were not sold intermingled.
		8B					837 Sales of FGD By-products (Lines 6 and 7) were reported on Schedule 8, Part A. Please enter the revenue (Part 14) in units of thousand dollars from those sales on Schedule 8B. Example: enter revenue of 5 million dollars as 5,000, not 5,000,000.		Sales of FGD By-products were \$1.00 which is less than what can be entered.
		8C		/SP			890 Acid Gas Removal Efficiency cannot be null if hours in service are provided. Please review reported data.		This equipment is intended for SO2 control. While it may remove acid gases, that is not its intended function so removal efficiency is unknown.
		8C		1/SN			1802 Hours in Service for NOx controls should not be blank or zero if there was consumption in Schedules 3A and/or 3C. Please review reported data to make a correction or provide an explanation.		Equipment was planned and being installed in 2017, but was not operational.
		8C		2/SN			1802 Hours in Service for NOx controls should not be blank or zero if there was consumption in Schedules 3A and/or 3C. Please review reported data to make a correction or provide an explanation.		Equipment was planned and being installed in 2017, but was not operational.
		8C		2/SP			851 The Removal Efficiency tested at 100% load for sulfur dioxide is outside the expected range of 50%-99%. If correct, enter a comment to explain data out of typical range.		The removal efficiency is 98.7% which is within the expected range of 50%-99%.
		8D		1	10		855 The maximum temperature reported for the month is outside normal bounds (32-100 degrees F) at the intake for the plant.		The unit was offline this month and did not operate.
		8D		1	10		856 The maximum temperature reported for the month is outside normal bounds (32-120 degrees F) at the discharge for the plant.		The unit was offline this month and did not operate.
		8D		1	10		857 The average temperature reported for the month is outside normal bounds (32-100 degrees F) at the intake for the plant.		The unit was offline this month and did not operate.
		8D		1	10		858 The average temperature reported for the month is outside normal bounds (32-110 degrees F) at the discharge for the plant.		The unit was offline this month and did not operate.

EXHIBIT 2

Summer/Winter Loads

Basin Electric Member Loads by State

Note: Historical 1995-2017 and Forecasted 2018-2028

SUMMER Peak Demand (MW)

	ND	SD	MN	IA	NE	MT	CO	WY	% BEPC TOTAL
1995	223.9	223.9	38.9	71.6	186.2	21.8	77.9	148.9	14.8%
1996	222.1	226.6	38.4	67.0	170.2	27.2	78.2	160.7	16.3%
1997	244.0	239.0	41.3	77.6	195.5	26.8	83.3	171.6	15.9%
1998	248.7	228.5	47.1	83.2	211.3	28.1	84.3	162.8	14.3%
1999	267.9	224.4	52.5	102.2	197.4	28.3	83.9	173.8	14.6%
2000	292.6	230.0	53.9	102.2	197.4	28.3	83.9	173.8	14.6%
2001	306.5	232.2	58.0	116.7	214.9	28.9	82.4	199.9	15.7%
2002	315.3	231.3	58.0	127.1	227.3	30.3	81.9	217.9	15.8%
2003	353.0	238.8	57.8	127.1	227.3	30.3	81.9	217.9	15.8%
2004	328.8	235.9	57.8	121.4	203.1	28.9	81.9	217.9	15.8%
2005	356.6	235.9	55.4	119.0	233.4	28.9	81.9	217.9	15.8%
2006	400.0	207.6	62.0	131.1	269.7	74.2	130.1	296.4	17.2%
2007	451.9	207.6	71.4	187.9	272.9	82.0	134.3	358.0	18.4%
2008	464.6	225.4	91.6	186.1	261.6	86.4	135.2	388.9	18.9%
2009	448.3	214.4	87.5	177.0	270.1	73.8	142.2	426.4	20.7%
2010	509.1	205.5	101.6	201.0	231.5	64.8	145.4	400.1	19.1%
2011	543.4	208.8	118.1	201.0	231.5	64.8	145.4	400.1	19.1%
2012	693.0	231.1	169.2	280.3	333.4	104.4	178.5	377.2	12.6%
2013	812.2	263.5	223.5	433.1	311.2	178.2	194.6	372.0	12.3%
2014	889.0	347.7	259.9	459.1	298.9	187.0	194.6	342.0	10.4%
2015	1186.6	347.7	259.9	459.1	298.9	187.0	194.6	342.0	10.4%
2016	1141.3	342.7	212.4	425.1	265.5	176.4	200.4	307.6	9.2%
2017	1243.5	342.7	212.4	425.1	265.5	176.4	200.4	307.6	9.2%
2018	1206.7	327.7	248.2	468.8	298.3	283.4	273.2	301.4	8.0%
2019	1228.0	327.7	248.2	468.8	298.3	283.4	273.2	301.4	8.0%
2020	1245.3	327.7	248.2	468.8	298.3	283.4	273.2	301.4	8.0%
2021	1264.4	327.7	248.2	468.8	298.3	283.4	273.2	301.4	8.0%
2022	1284.9	318.5	296.7	505.6	305.6	347.2	274.2	295.7	7.3%
2023	1302.9	318.5	308.1	512.4	308.1	360.0	274.2	295.7	7.3%
2024	1319.0	313.3	319.5	512.4	308.1	360.0	274.2	295.7	7.3%
2025	1334.4	313.3	321.1	512.4	308.1	360.0	274.2	295.7	7.3%
2026	1349.7	313.3	357.1	519.5	310.3	383.0	274.6	286.6	6.8%
2027	1364.6	313.3	368.1	523.0	311.2	387.1	274.7	282.7	6.5%
2028	1379.1	313.3	378.4	526.6	312.1	388.7	274.9	280.6	6.4%

WINTER Peak Demand (MW)

	ND	SD	MN	IA	NE	MT	CO	WY	% BEPC TOTAL
95/96	325.8	29.4%	309.0	51.2	33.3	31.6	77.4	189.9	17.2%
96/97	334.5	29.3%	302.7	47.9	35.7	30.2	78.5	210.7	18.5%
97/98	324.0	30.5%	263.3	77.5	35.8	29.3	83.5	207.9	19.6%
98/99	331.3	29.2%	291.8	109.2	37.0	30.4	84.3	201.2	17.8%
99/00	312.3	28.8%	269.3	102.3	31.0	28.0	83.9	209.0	19.3%
00/01	342.1	27.4%	328.0	124.6	42.5	33.6	82.4	238.7	19.1%
01/02	312.5	26.2%	274.4	108.4	42.5	34.9	83.2	238.7	19.1%
02/03	376.7	27.7%	342.3	127.8	35.7	34.9	103.1	267.5	19.6%
03/04	416.9	27.5%	393.8	134.2	35.7	34.9	103.1	267.5	19.6%
04/05	437.9	27.4%	416.6	138.7	43.5	62.4	122.5	293.2	19.3%
05/06	462.6	26.8%	414.7	186.6	48.4	72.2	120.8	314.4	19.7%
06/07	494.6	25.4%	484.4	211.5	50.0	80.7	121.8	353.4	20.5%
07/08	562.7	26.3%	524.3	231.7	50.0	78.3	137.8	402.6	20.7%
08/09	622.7	25.7%	633.9	276.1	56.8	73.6	132.5	454.0	21.2%
09/10	627.3	23.5%	618.6	333.3	58.8	55.5	144.9	481.0	19.9%
10/11	678.7	25.2%	621.6	317.7	54.5	55.5	144.9	481.0	19.9%
11/12	834.7	29.5%	999.9	468.3	49.3	100.6	182.8	566.9	15.9%
12/13	972.6	32.3%	777.8	523.1	52.4	183.1	199.9	651.3	11.8%
13/14	1134.3	31.9%	699.7	495.7	56.6	160.5	184.4	365.3	11.8%
14/15	1358.8	37.2%	699.7	495.7	56.6	160.5	184.4	365.3	11.8%
15/16	1394.3	39.9%	634.4	466.0	53.6	160.5	184.4	365.3	11.8%
16/17	1441.3	38.7%	694.5	476.5	52.9	160.5	184.4	365.3	11.8%
17/18	1545.5	39.8%	718.0	493.2	47.0	152.4	184.4	365.3	11.8%
18/19	1463.0	37.8%	709.6	532.0	47.7	129.2	184.4	365.3	11.8%
19/20	1483.4	38.1%	719.9	535.5	48.0	129.2	184.4	365.3	11.8%
20/21	1506.5	38.1%	734.9	539.7	48.0	129.2	184.4	365.3	11.8%
21/22	1528.7	38.1%	750.6	543.9	48.4	129.2	184.4	365.3	11.8%
22/23	1553.0	37.1%	834.1	548.4	48.8	129.2	184.4	365.3	11.8%
23/24	1573.4	36.7%	878.1	548.4	48.8	129.2	184.4	365.3	11.8%
24/25	1592.7	36.5%	911.9	554.6	49.2	129.2	184.4	365.3	11.8%

EXHIBIT 3

Eastern System Summer/Winter Load Resources

SPP SUMMER SEASON				
	Members' Load Projections *	Contracted Sales to Others	Losses & Diversity	Total Responsibility
2018	2,562	239	436	3,237
2019	2,636	176	448	3,261
2020	2,670	197	454	3,321
2021	2,706	163	462	3,332
2022	2,840	157	483	3,480
2023	2,913	163	496	3,572
2024	2,973	157	505	3,634
2025	3,009	164	512	3,684
2026	3,042	240	516	3,798
2027	3,076	248	523	3,847
2028	3,110	294	528	3,931

SPP WINTER SEASON				
	Members' Load Projections *	Contracted Sales to Others	Losses & Diversity	Total Responsibility
2018/19	2,699	140	455	3,294
2019/20	2,727	177	461	3,365
2020/21	2,772	207	469	3,448
2021/22	2,812	157	487	3,455
2022/23	2,950	157	502	3,609
2023/24	3,029	157	512	3,698
2024/25	3,097	157	520	3,774
2025/26	3,135	220	525	3,880
2026/27	3,174	221	531	3,927
2027/28	3,213	287	536	4,037

MISO Z1 SUMMER SEASON				
	Members' Load Projections *	Contracted Sales to Others	Losses & Diversity	Total Responsibility
2018	205	0	21	226
2019	215	0	22	237
2020	228	0	23	251
2021	236	0	24	260
2022	244	0	25	270
2023	254	0	26	280
2024	263	0	27	290
2025	273	0	29	301
2026	283	0	30	313
2027	292	0	31	323
2028	300	0	32	332

MISO Z1 WINTER SEASON				
	Members' Load Projections *	Contracted Sales to Others	Losses & Diversity	Total Responsibility
2018/19	295	0	30	325
2019/20	300	0	30	330
2020/21	308	0	31	339
2021/22	317	0	33	350
2022/23	327	0	34	361
2023/24	337	0	35	372
2024/25	347	0	36	384
2025/26	358	0	38	396
2026/27	368	0	39	407
2027/28	378	0	40	418

2018 Resources

Summer Season

SPP

LOS	LRS East	AVS ¹	Neal4 ³	WS ⁴	Wisdom1	Wisdom2	DAEC ²	SMS	GGS	CGS	DCS	PGS	LCS	Madison	Webster City	Estherville	Spencer	Wind	Waste Heat	MISO Z1	
																				Purchases	Purchases
2018	665.0	48.0	904.0	-	36.3	69.4	-	95.6	176.0	85.5	297.0	238.0	206.2	10.0	20.7	13.0	10.0	132.0	27.0	505.0	300.0
2019	665.0	39.0	904.0	-	36.3	69.4	-	95.6	176.0	85.5	297.0	238.0	206.2	10.0	20.7	13.0	10.0	136.7	27.0	305.0	325.0
2020	665.0	40.0	904.0	-	36.3	69.4	-	95.6	176.0	85.5	297.0	238.0	206.2	10.0	20.7	13.0	10.0	184.4	27.0	304.0	300.0
2021	665.0	40.0	561.2	107.2	36.3	69.4	60.2	95.6	176.0	85.5	297.0	238.0	206.2	10.0	20.7	13.0	10.0	184.4	27.0	252.0	350.0
2022	665.0	40.0	561.2	107.2	36.3	69.4	60.2	95.6	176.0	85.5	297.0	238.0	206.2	10.0	20.7	13.0	10.0	182.8	27.0	251.0	325.0
2023	665.0	40.0	561.2	107.2	36.3	69.4	60.2	95.6	176.0	85.5	297.0	238.0	206.2	10.0	20.7	13.0	10.0	202.4	27.0	250.0	200.0
2024	665.0	40.0	561.2	107.2	36.3	69.4	60.2	95.6	176.0	85.5	297.0	238.0	206.2	10.0	20.7	13.0	10.0	202.4	27.0	99.0	200.0
2025	665.0	40.0	561.2	107.2	36.3	69.4	60.2	95.6	176.0	85.5	297.0	238.0	206.2	10.0	20.7	13.0	10.0	202.4	27.0	98.0	-
2026	665.0	39.0	561.2	107.2	36.3	69.4	-	95.6	176.0	85.5	297.0	238.0	206.2	-	20.7	13.0	10.0	202.4	27.0	97.0	-
2027	665.0	39.0	561.2	107.2	36.3	69.4	-	95.6	176.0	85.5	297.0	238.0	206.2	-	20.7	13.0	10.0	202.4	27.0	96.0	-
2028	665.0	39.0	561.2	107.2	36.3	69.4	-	95.6	176.0	85.5	297.0	238.0	206.2	-	20.7	13.0	10.0	202.4	27.0	95.0	-

Winter Season

SPP

LOS	LRS East	AVS ¹	Neal4 ³	WS ⁴	Wisdom1	Wisdom2	DAEC ²	SMS	GGS	CGS	DCS	PGS	LCS	Madison	Webster City	Estherville	Spencer	Wind	Waste Heat	MISO Z1	
																				Purchases	Purchases
2018/19	665.0	48.0	904.0	-	37.9	80.8	-	120.0	187.7	93.1	300.0	242.8	225.2	10.0	25.6	13.0	10.0	361.0	32.6	582.6	300.0
2019/20	665.0	40.0	904.0	-	37.9	80.8	-	120.0	187.7	93.1	300.0	242.8	225.2	10.0	25.6	13.0	10.0	522.4	32.6	581.6	325.0
2020/21	665.0	40.0	561.2	-	37.9	80.8	-	120.0	187.7	93.1	300.0	242.8	225.2	10.0	25.6	13.0	10.0	574.9	32.6	580.6	300.0
2021/22	665.0	40.0	561.2	107.2	37.9	80.8	62.2	120.0	187.7	93.1	300.0	242.8	225.2	10.0	25.6	13.0	10.0	574.8	32.6	528.6	350.0
2022/23	665.0	40.0	561.2	107.2	37.9	80.8	62.2	120.0	187.7	93.1	300.0	242.8	225.2	10.0	25.6	13.0	10.0	699.3	32.6	527.6	325.0
2023/24	665.0	40.0	561.2	107.2	37.9	80.8	62.2	120.0	187.7	93.1	300.0	242.8	225.2	10.0	25.6	13.0	10.0	699.3	32.6	376.6	200.0
2024/25	665.0	40.0	561.2	107.2	37.9	80.8	62.2	120.0	187.7	93.1	300.0	242.8	225.2	10.0	25.6	13.0	10.0	699.3	32.6	375.6	200.0
2025/26	665.0	39.0	561.2	107.2	37.9	80.8	-	120.0	187.7	93.1	300.0	242.8	225.2	-	25.6	13.0	10.0	699.3	32.6	374.6	-
2026/27	665.0	39.0	561.2	107.2	37.9	80.8	-	120.0	187.7	93.1	300.0	242.8	225.2	-	25.6	13.0	10.0	699.3	32.6	373.6	-
2027/28	665.0	39.0	561.2	107.2	37.9	80.8	-	120.0	187.7	93.1	300.0	242.8	225.2	-	25.6	13.0	10.0	699.3	32.6	372.6	-

Footnotes:

1) BEPC owns 24.166% of AVS unit 2 and leases the remaining portion from other owners. The terms of the lease end 12/31/2020 and Basin Electric currently doesn't intend to renew them.

2) It is likely the DAEC unit will shutdown at the end of 2025 unless NextEra can find an offtaker for their 70% of the unit; DAEC is currently in MISO Z3, and Basin Electric plans to bring it back into SPP by summer 2021

3) Neal 4 is currently in MISO Z3, and Basin Electric plans to bring it back into SPP by summer 2021

4) WS 3 & 4 are currently in MISO Z3, and Basin Electric plans to leave them there for the foreseeable future