

PROSPECTUS



Offer to Exchange
\$700,000,000 aggregate principal amount of
5.850% First Mortgage Obligations, 2025 Series A Bonds due 2055
for
\$700,000,000 aggregate principal amount of
5.850% First Mortgage Obligations, 2025 Series A Bonds due 2055
that have been registered under the Securities Act of 1933, as amended (the “Securities Act”)

**The Exchange Offer will expire at 5:00 p.m., New York City time,
on June 4, 2026, unless extended.**

We hereby offer, upon the terms and subject to the conditions set forth in this prospectus and the accompanying letter of transmittal, to exchange up to \$700,000,000 aggregate principal amount of our outstanding 5.850% First Mortgage Obligations, 2025 Series A Bonds due 2055 (CUSIP Nos. 070101 AJ9 and U06865 AB2) (the “Original Bonds”) for a like principal amount of our 5.850% First Mortgage Obligations, 2025 Series A Bonds due 2055 that have been registered under the Securities Act (CUSIP No. 070101 AK6) (the “Exchange Bonds”). We refer to this offer as the “Exchange Offer.” When we use the term “Bonds” in this prospectus, the term includes the Original Bonds and the Exchange Bonds unless otherwise indicated or the context otherwise requires. The terms of the Exchange Offer are summarized below and are more fully described in this prospectus.

The terms of the Exchange Bonds are substantially identical to the terms of the Original Bonds, except that the transfer restrictions, registration rights and additional interest provisions applicable to the Original Bonds do not apply to the Exchange Bonds. The Exchange Bonds will be secured equally and ratably with all our other obligations issued under the Amended and Restated Indenture, dated as of May 5, 2015, as amended and supplemented (the “Indenture”), with U.S. Bank Trust Company, National Association, successor-in-interest to U.S. Bank National Association, as trustee (the “Trustee”), by a mortgage lien on substantially all of our owned tangible and certain of our intangible properties, subject to certain exceptions and exclusions as described or referred to in this prospectus.

We will accept for exchange any Original Bonds validly tendered and not validly withdrawn at any time prior to 5:00 p.m., New York City time, on June 4, 2026, unless extended (the “expiration date”).

You may withdraw tenders of Original Bonds at any time before 5:00 p.m., New York City time, on the expiration date.

We will not receive any cash proceeds from the issuance of the Exchange Bonds in the Exchange Offer. The Original Bonds surrendered and exchanged for the Exchange Bonds will be retired and canceled. Accordingly, the issuance of the Exchange Bonds will not result in any increase in our outstanding indebtedness.

The exchange of Original Bonds for Exchange Bonds pursuant to the Exchange Offer generally will not be treated as a taxable exchange for U.S. federal income tax purposes.

No public market currently exists for the Original Bonds. We do not intend to list the Exchange Bonds on any securities exchange and, therefore, no active public market is anticipated.

Each broker-dealer that receives Exchange Bonds for its own account pursuant to the Exchange Offer must acknowledge that it will deliver a prospectus in connection with any resale of such Exchange Bonds. The letter of transmittal states that by so acknowledging and by delivering a prospectus, a broker-dealer will not be deemed to admit that it is an “underwriter” within the meaning of the Securities Act. This prospectus, as it may be amended or supplemented from time to time, may be used by a broker-dealer in connection with resales of Exchange Bonds received in exchange for Original Bonds where such Original Bonds were acquired by such broker-dealer acquired as a result of market-making activities or other trading activities. We have agreed that we will make this prospectus available to any broker-dealer for use in connection with any such resale for a period of 180 days following the expiration date of the Exchange Offer or such time as such broker-dealers no longer own any Original Bonds. See “[PLAN OF DISTRIBUTION](#).”

See “[RISK FACTORS](#)” beginning on page [13](#) for a discussion of certain factors that you should consider before tendering your Original Bonds.

Neither the U.S. Securities and Exchange Commission nor any state securities commission has approved or disapproved of these securities or determined if this prospectus is truthful or complete. Any representation to the contrary is a criminal offense.

The date of this prospectus is May 6, 2026.

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ABOUT THIS PROSPECTUS

You should rely only on the information contained in this prospectus. We have not authorized any person to give any information to you or to make any representation other than those contained in this prospectus in connection with the Exchange Offer and, if given or made, such information or representation must not be relied upon as having been authorized by us. You should not assume that the information contained in this prospectus is accurate as of any date other than the date on the cover of this prospectus. Our business, financial condition and results of operations may have changed since that date.

In this prospectus, except as the context otherwise requires or as otherwise noted, “Basin Electric,” “we,” “us” and “our” refer to Basin Electric Power Cooperative and its subsidiaries that are consolidated under GAAP, except with respect to the Bonds, in which case such terms refer only to Basin Electric Power Cooperative.

WHERE YOU CAN FIND MORE INFORMATION

We have filed with the Securities and Exchange Commission (the “SEC”) a registration statement on Form S-4 under the Securities Act relating to the securities covered by this prospectus. This prospectus is a part of the registration statement and does not contain all of the information in the registration statement. Whenever a reference is made in this prospectus to a contract or other document of ours, please be aware that the reference is only a summary and that you should refer to the exhibits that are a part of the registration statement for a copy of the contract or other document. You may review a copy of the registration statement through the SEC’s website referred to below.

We are not currently subject to the informational requirements of the Securities Exchange Act of 1934, as amended (the “Exchange Act”). As a result of the offering of the Exchange Bonds, we will become subject to the informational requirements of the Exchange Act, and, in accordance therewith, will file reports and other information with the SEC. The SEC maintains a website at www.sec.gov that contains reports and other information regarding issuers that file electronically with the SEC. The information contained on or accessible through our website or any other website that we may maintain is not incorporated by reference herein and is not part of this prospectus or the registration statement of which this prospectus is a part.

In addition, for so long as any of the Bonds remain outstanding and are “restricted securities” within the meaning of Rule 144(a)(3) under the Securities Act, we have agreed that we will, during any period in which we are not subject to and in compliance with Section 13(a) or 15(d) of the Exchange Act, or do not make voluntary filings pursuant to such Sections, furnish at our expense, upon the request of any holder of a Bond, such information as specified in Rule 144A(d)(4) under the Securities Act to such holder and to a prospective purchaser of such Bond (or beneficial interests therein) designated by such holder, in each case in order to permit compliance by such holder with Rule 144A in connection with the resale of such Bond (or beneficial interests therein) in reliance upon Rule 144A. See “[DESCRIPTION OF THE EXCHANGE BONDS](#).”

This prospectus contains summaries of the terms of several material documents. These summaries include the terms that we believe to be material, but we urge you to review these documents in their entirety. We will provide without charge to each person to whom a copy of this prospectus is delivered, upon written or oral request of that person, a copy of any and all of this information. All requests for information, including the information required to be delivered pursuant to Rule 144A(d)(4), should be directed to us at Basin Electric Power Cooperative, 1717 East Interstate Avenue, Bismarck, North Dakota 58503-0564, Attention: Vice President & Treasurer or by calling us at (701) 223-0441. You should request this information at least five business days in advance of the date on which you expect to make your decision with respect to the Exchange Offer. In any event, you must request this information no later than May 28, 2026, which is five business days prior to the expiration date of the Exchange Offer, in order to receive the information prior to the expiration of the Exchange Offer.

FORWARD-LOOKING STATEMENTS

Except for the historical information contained in this prospectus, certain matters discussed in this prospectus, including (without limitation) statements under “[RISK FACTORS](#),” contain forward-looking statements within the meaning of Section 27A of the Securities Act and Section 21E of the Exchange Act. Although we believe that, in making any such statements, our expectations are based on reasonable assumptions, any such statement may be influenced by factors that could cause actual outcomes and results to be materially different from those projected.

These forward-looking statements include statements relating to our anticipated financial performance and business prospects or statements preceded by, followed by or that include the words “believe,” “will,” “so we can,” “when,” “anticipate,” “intend,” “estimate,” “forecast,” “expect,” “project,” “should,” “could,” “may,” “plan,” “seeks,” and similar expressions. Although we believe that in making the statements contained in this prospectus our expectations are based on reasonable assumptions, we can give no assurance that these expectations will prove to be correct or that we will achieve the financial results, savings or other benefits anticipated in the forward-looking statements. These forward-looking statements involve known and unknown risks, uncertainties and other important factors, some of which may be beyond our control, that could cause our actual results, performance or achievements or industry results, to differ materially from any future results, performance or achievements expressed or implied by these forward-looking statements. These risks, uncertainties and other important factors, including those disclosed under “[RISK FACTORS](#),” include, without limitation:

- unanticipated variation in demand for electric capacity or energy or load forecasts resulting from changes in population and economic growth (and declines), consumer consumption and energy conservation efforts, including the impact on power supply plans;
- the impact of traditional load growth and potential large loads, including data centers, in our members’ service territories and any decisions regarding the development of additional generation resources to meet the additional demand;
- changes in the market price of commodities, including natural gas, energy, crude oil, diesel and nitrogen-based fertilizer products;
- legislative and regulatory compliance standards and the cost and other burdens of complying with any applicable standards, including mandatory reliability standards, and potential penalties for non-compliance;
- new, amended, or existing laws, regulations, or administrative orders, including those related to environmental matters, carbon dioxide and other greenhouse gas emissions, water and coal combustion byproducts, and the costs of complying with these laws, regulations, and administrative orders;
- costs of additional generation or transmission facilities to meet the needs of our members or changes in the anticipated retirement dates of existing generation or transmission facilities;
- success or failure to consummate strategic transactions, including acquisition or divestiture activities, upon which we base financial or operational forecasts;
- the outcome or consequences of strategic alternatives that we are, or may in the future, evaluate in connection with our subsidiary, Dakota Gasification Company (“Dakota Gas”), including asset impairments;
- changes in customer preferences for energy produced from cleaner generation sources;
- continued efficient operation of our generation facilities by us;
- the ability of our member systems to perform their obligations to us;

- the pricing and availability of an adequate and economical supply of fuel, water and other materials;
- our ability to hedge power, fuel and capacity to provide margin visibility and mitigate market volatility;
- changes in utility regulation and the allocation of costs within regional transmission organizations, including the Southwest Power Pool (“SPP”) and Midcontinent Independent System Operator (“MISO”);
- pressures exerted by increasing levels of indebtedness caused by significant capital expenditures;
- unanticipated changes in capital expenditures, operating expenses and liquidity needs;
- our access to capital, the cost to access capital, and the results of our financing and refinancing efforts, including availability of funds in the capital markets;
- the availability of funding under any federal loan or grant programs for which we qualify and are awarded and our ability to meet the applicable loan or grant conditions and requirements;
- general economic, credit and capital market conditions;
- supply chain challenges, including as a result of trade policies, tariffs, or other international trade restrictions;
- failure of our information technology or operating technology;
- the direct or indirect effect on our business resulting from cyber or physical attacks on us, our members or third-party service providers, vendors or contractors;
- commercial banking and financial market conditions;
- hazards customary to the electric industry and the possibility that we may not have adequate insurance to cover losses resulting from these hazards;
- litigation or legal and administrative proceedings and settlements;
- the effectiveness of our risk management policies and risk strategies, including hedging, with respect to commodity prices, interest rates and counterparty credit and non-performance risks;
- the credit quality or inability of various counterparties to meet their financial obligations to us, including failure to perform under agreements;
- unanticipated changes in interest rates or rates of inflation;
- acts of sabotage, wars or terrorist activities, including cyber or physical attacks on our assets or assets on which we rely;
- catastrophic events such as wildfires, earthquakes, floods, droughts, tornadoes, mechanical failures, explosions, pandemic health events, or similar occurrences;
- changes in technology available to and utilized by us or our competitors;
- significant changes in critical accounting policies material to us;
- significant changes in our relationship with our employees, including the availability of qualified personnel; and

- weather conditions and other natural phenomena.

For more information on these and other factors, see “[RISK FACTORS](#).” In light of these risks, uncertainties and assumptions, we caution you not to place undue reliance on any forward-looking statements. The forward-looking statements included in this prospectus are made only as of the date of this prospectus and we do not undertake any obligation to update or revise publicly any forward-looking statements, whether as a result of new information, future events or otherwise, except as required by law.

CERTAIN DEFINITIONS

Except where otherwise noted, or the context otherwise requires, the following capitalized terms, abbreviations, and acronyms have the meanings set forth below:

Abbreviations or Acronyms	Definitions
AI	Artificial intelligence
ASC	Financial Accounting Standards Board (FASB) Accounting Standards Codification
Basin Cooperative Services	Basin Cooperative Services, a wholly owned subsidiary of Basin Electric that operates on a not-for-profit basis. Basin Cooperative Services provides certain nonutility property management services to us
Basin Electric, we, our, us, and similar terms	Basin Electric Power Cooperative and, in the case of GAAP financial statements, our consolidated subsidiaries
Board	The Board of Directors of Basin Electric
CCR Rule	Coal Combustion Residuals Rule
CFC	National Rural Utilities Cooperative Finance Corporation
Class A Members	Class A Members consist of ten wholesale G&T cooperatives, eight distribution cooperatives and one wholesale municipal provider that have entered into long-term wholesale power contracts with us
Class B Members	Class B Members consist of any municipality or association of municipalities operating within an area served by a Class A Member and which is a member of, and contracts for its electric capacity or energy from, that Class A Member, and which is not eligible for Class C Membership
Class C Members	Class C Members consist of distribution cooperatives and public power districts that are members of a Class A Member and contract for a portion of their electric power and energy from the Class A Member
Class D Members	Class D Members consist of electric cooperatives, municipalities, or associations of municipalities which purchase power directly from us on a basis other than as a Class A, Class B, or Class C Member
Clean Air Act	A U.S. federal law that regulates air emissions from stationary and mobile sources to protect public health and the environment
Clean Water Act	A U.S. federal law that governs water pollution, aiming to ensure clean surface waters by regulating discharges into navigable waters
CO ₂	Carbon dioxide
Code	Internal Revenue Code of 1986, as amended
Corn Belt	Corn Belt Power Cooperative, a Class A Member
Coteau	The Coteau Properties Company, a subsidiary of North American Coal Corporation
Coteau Lignite Sales Agreement	Dakota Coal purchases lignite coal from Coteau on a cost-plus basis pursuant to this sales agreement with Coteau
D.C. Circuit	United States Court of Appeals for the D.C. Circuit
Dakota Coal	Dakota Coal Company, a wholly owned subsidiary of Basin Electric that operates on a for-profit basis
Dakota Gas	Dakota Gasification Company, a wholly owned subsidiary of Basin Electric that operates on a for-profit basis
DC	Direct Current
DCS	Dakota Carbon Services LLC
DEF	Diesel exhaust fluid

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DFS	Dry Fork Generation Station
DOE	United States Department of Energy
DTC	The Depository Trust Company
East River	East River Electric Power Cooperative, Inc., a Class A Member
EPA	United States Environmental Protection Agency
ERISA	Employee Retirement Income Security Act of 1974
ERISA Plan	Plan subject to Title I of ERISA or Section 4975 of the Code
Exchange Act	Securities Exchange Act of 1934, as amended
FASB	Financial Accounting Standards Board
FATCA	Foreign Account Tax Compliance Act
Federal Power Act	Federal Power Act of 1920, as amended, and the rules and regulations adopted by FERC thereunder
FERC	Federal Energy Regulatory Commission
FIP	Federal Implementation Plan
Fitch	Fitch Ratings Inc.
Freedom Mine	A large lignite coal mine near Beulah, ND, operated by The Coteau Properties Company
G&T	Generation and transmission
GAAP	Accounting principles generally accepted in the U.S.
GHG	Greenhouse gas
Indenture	Amended and Restated Indenture, dated as of May 5, 2015, between Basin Electric and U.S. Bank Trust Company, National Association, as trustee, as amended and supplemented
IRS	United States Internal Revenue Service
kV	Kilovolt
kWh	Kilowatt-hour
LMP	Locational marginal pricing in an energy market
LRS	Laramie River Station
MBPP	Missouri Basin Power Project
McKenzie	McKenzie Electric Cooperative, Inc., a Class C Member
Members	Our electric distribution member systems, consisting of Class A Members, Class B Members, Class C Members, and Class D Members
MFI Ratio	Margins for Interest Ratio
Minnesota Valley	Minnesota Valley Electric Cooperative, a Class A Member
MIP	Member Investment Program
MISO	Midcontinent Independent System Operator, Inc.
MMbtu/day	Million British Thermal Units per day
MMcf/day	Million Cubic Feet per day
Montana Limestone	Montana Limestone Company, a wholly owned subsidiary of Dakota Coal
Moody's	Moody's Investors Services, Inc.
MRO	Midwestern Reliability Organization
MVAR	Megavolt-amps reactive
MW	Megawatt
MWh	Megawatt-hour
NAAQS	National Ambient Air Quality Standards

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Nemadji River Generation	Nemadji River Generation LLC, previous owner of a 30% undivided interest in NTEC
NEO	Named Executive Officers
NERC	North American Electric Reliability Corporation
New ERA	RUS Empowering Rural America Program
Northern Border	Northern Border Pipeline Company
NO _x	Nitrogen oxide
NTEC	Nemadji Trail Energy Center, a proposed 600-megawatt natural gas-fired combined-cycle electric generation facility that was previously planned to be constructed in Wisconsin
PCAOB	Public Company Accounting Oversight Board (United States)
Pioneer Generation Station Phase IV	Pioneer Generation Station Unit 4, Unit 5 and Units 31-36
PRECorp	Powder River Energy Corporation, a Class C Member
PRM	Planning reserve margin
PSCo	Public Service Company of Colorado
PURPA	Public Utility Regulatory Policies Act of 1978, as amended
RE Act	Rural Electrification Act of 1936
RMR	Rocky Mountain region
RMSC	Risk Management Steering Committee of Basin Electric
RTO	Regional transmission organization
RUS	Rural Utilities Service, which provides funding for the development of rural utilities infrastructure such as water, waste management, power and telecommunications under the U.S. Department of Agriculture
S&P	S&P Global Ratings, a division of S&P Global Inc.
SEC	United States Securities and Exchange Commission
Section 45Q	Section 45Q of the Code, which provides a federal tax credit for carbon oxide (CO ₂ and CO) capture and sequestration
Securities Act	Securities Act of 1933, as amended
SNG	Synthetic Natural Gas
SO ₂	Sulfur Dioxide
SPP	Southwest Power Pool, Inc.
Synfuels Plant	Great Plains Synfuels Plant
Tri-State	Tri-State Generation & Transmission Association, Inc., a Class A Member
UGP	Upper Great Plains
Upper Missouri	Upper Missouri G & T Electric Cooperative, Inc., doing business as Upper Missouri Power Cooperative, a Class A Member
U.S.	United States of America
WAPA	Western Area Power Administration
WECC	Western Electricity Coordinating Council, a non-profit corporation that exists to assure a reliable Bulk Electric System in the geographic area known as the Western Interconnection
Western Fuels	Western Fuels Association, a non-profit Wyoming corporation founded by us and Tri-State
WMPA	Wyoming Municipal Power Agency, a Class A Member
WPP	Western Power Pool

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Wright-Hennepin	Wright-Hennepin Cooperative Electric Association, a Class A Member
Wyoming Lime	Wyoming Lime Producers, a division of Dakota Coal

SUMMARY

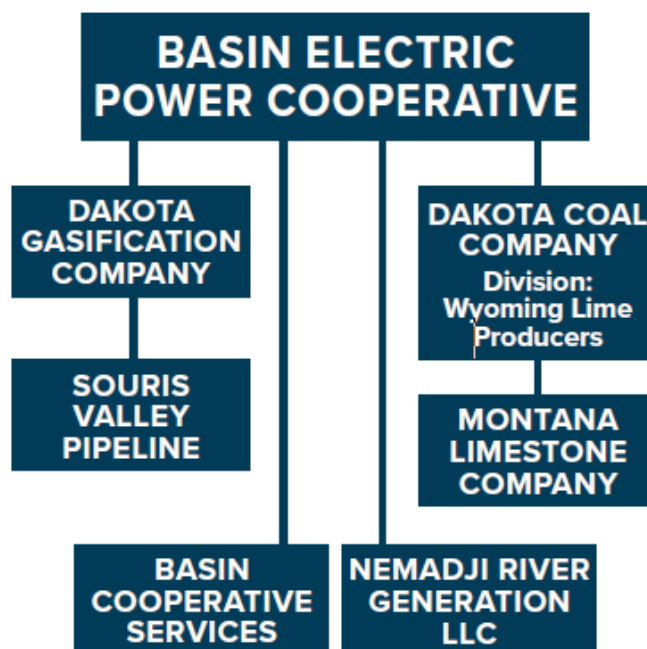
This summary highlights selected information contained elsewhere in this prospectus. This summary is not complete and does not contain all of the information that may be important to you. For a more complete understanding of our business and the Exchange Offer, you should read this entire prospectus, including [“RISK FACTORS,”](#) [“FORWARD-LOOKING STATEMENTS,”](#) [“MANAGEMENT’S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS”](#) and our consolidated financial statements and the notes thereto included herein.

Overview

We were formed under the laws of the State of North Dakota in 1961 as a not-for-profit generation and transmission (“G&T”) cooperative corporation. We are based in Bismarck, North Dakota, and are principally engaged in the business of providing wholesale electric services to our members through long-term wholesale power contracts. These electric services generally represent the capacity and energy requirements of our members beyond that available to our members from other sources, primarily the Western Area Power Administration (“WAPA”), an agency of the United States Department of Energy (“DOE”) that provides hydroelectric power and transmission services to our members. We are the largest G&T cooperative in the United States in terms of land area served by our members. Our G&T members provide wholesale electric service for 138 rural electric and small municipal electric systems to approximately 3.0 million people in the States of Colorado, Iowa, Minnesota, Montana, Nebraska, New Mexico, North Dakota, South Dakota, and Wyoming.

We also have two significant wholly owned subsidiaries that operate on a for-profit basis: Dakota Gasification Company (“Dakota Gas”), which owns and operates the Great Plains Synfuels Plant (the “Synfuels Plant”), through which it produces and sells synthetic natural gas and other products of the coal gasification process; and Dakota Coal Company (“Dakota Coal”), which supplies lignite coal to us for fuel at Antelope Valley Station and Leland Olds Station, and to Dakota Gas for use at the Synfuels Plant.

The following diagram depicts our organizational structure as of December 31, 2025. This chart is provided for illustrative purposes only and does not purport to represent all legal entities within our organizational structure:

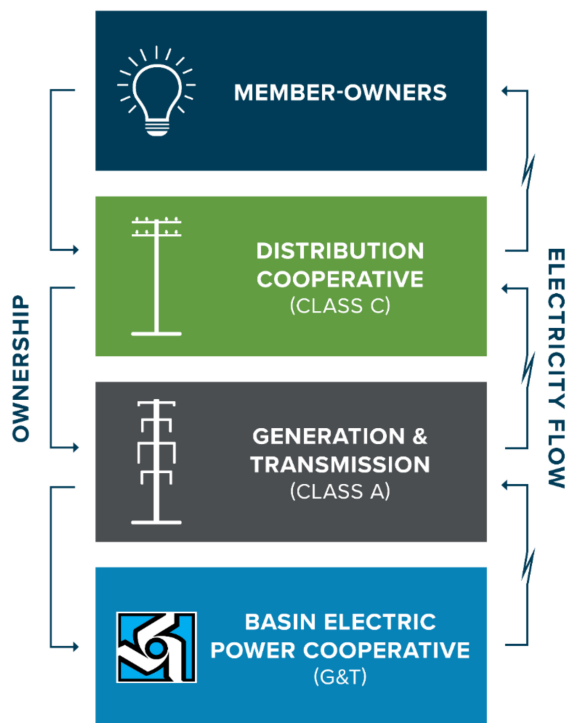


Our Members

We are a membership corporation, and our members are not subsidiaries. Our 138 members are classified into four classes (Class A, B, C and D, respectively) depending upon how they are supplied with our electric services:

- Our Class A Members consist of ten wholesale G&T cooperatives, eight distribution cooperatives and one wholesale municipal provider that have entered into long-term wholesale power contracts with us (the “Class A Members”). We supply power directly to and receive revenue directly from our Class A Members. Our operating revenue comes primarily from our Class A Members, and for the years ended December 31, 2025 and 2024, our Class A Members contributed approximately 90.5% and 88.1% of our electric sales revenue, respectively.
- Our Class B Members consist of any municipality or association of municipalities operating within an area served by a Class A Member and which is a member of, and contracts for its electric capacity or energy from, that Class A Member (the “Class B Members”). We currently have one Class B Member. We do not supply power directly to, or receive revenue directly from, our Class B Member.
- Our Class C Members consist of distribution cooperatives and public power districts that are members of our G&T Class A Members (the “Class C Members”). Our Class C Members do not purchase power directly from us, but rather from their respective G&T Class A Members. We currently have 117 Class C Members. We do not supply power directly to, or receive revenue directly from, our Class C Members.
- Our Class D Members consist of electric cooperatives that purchase power directly from us on a basis other than the long-term wholesale power contracts that we have with our Class A Members (the “Class D Members”). We currently have one Class D Member.

The following diagram depicts our membership structure:



Wholesale Power Contracts

We supply our Class A Members, the primary purchasers of our power, through long-term wholesale power contracts. Pursuant to these contracts, we generally sell and deliver to each Class A Member, except Tri-State Generation & Transmission Association, Inc. (“Tri-State”), all of such member’s capacity and associated energy requirements in excess of enumerated amounts of capacity and associated energy available to such member from other specified sources, primarily WAPA. Our wholesale power contracts with our Class A Members provide that capacity and associated energy are to be furnished in accordance with the member’s normal annual load patterns and that our obligations are limited to the extent to which we have capacity, energy and facilities available. All of our wholesale power contracts with our Class A Members extend through 2075, with the exception of our wholesale power contracts with Tri-State, Minnesota Valley Electric Cooperative (“Minnesota Valley”), Wright-Hennepin Cooperative Electric Association (“Wright-Hennepin”) and Wyoming Municipal Power Agency (“WMPA”), which extend through 2050. In 2025, revenues from electric sales to members with wholesale power contracts expiring in 2050 were approximately 10.1% of our total members sales. After maturity in 2050 or 2075, as applicable, these contracts remain in effect until terminated by either party giving the contractually required notice of its intention to terminate. Some of our Class A Members are themselves wholesale cooperatives like us, and with limited exceptions, the wholesale power contracts they have with their members align with or extend beyond the corresponding expiration dates as our contracts with their respective Class A Member. See “[BUSINESS—Wholesale Power Contracts](#).”

Power Supply and Transmission

Our power supply resources are comprised of generating facilities that we own, lease or have undivided ownership interests in, and for which we have contractual power purchase agreements. As of December 31, 2025, we operated, directly or indirectly, approximately 5,859 megawatts (“MW”) of generating capability in North Dakota, South Dakota, Montana, Iowa, and Wyoming. We currently own or lease interests in eight base load, coal-fired generating units, two oil-fired generating units, twenty-two natural gas-fired combustion turbine generating units, one natural gas-fired combined-cycle generating unit, eighteen natural gas-based reciprocating engines, one dual fuel (natural gas and oil) combustion turbine and 188 wind-powered turbines. See “[BUSINESS—Power Supply](#)” and “[PROPERTIES—Generating Facilities](#).”

We also have purchase arrangements which supply us with approximately 4,198 MW of power as of December 31, 2025, including 309 MW from our Class A Member, Corn Belt Power Cooperative (“Corn Belt”), and many wind and solar generating facilities.

Our transmission resources are comprised of more than 2,500 miles of owned high-voltage transmission lines as of December 31, 2025, and 220 telecommunication sites. Additionally, we own or maintain equipment in 115 substation locations. Further, we both own and have long-term contractual rights to direct current ties enabling power transfers between the eastern and western interconnections. We are also participants in the Southwest Power Pool (“SPP”) and the Midcontinent Independent System Operator (“MISO”) regional transmission organizations (“RTOs”). See “[BUSINESS—Transmission](#).”

Rate Setting

Each Class A Member is required to pay us for capacity and energy furnished under its wholesale power contract with us in accordance with our established rates. Our wholesale power contracts with our Class A Members provide that our board of directors (“Board”) will establish rates to produce revenue sufficient, together with all of our other revenue, to pay the cost of operation and maintenance of all our generation, transmission system and related facilities, the cost of any power and energy purchased for resale by us, the cost of transmission service, the cost of lease payments, interest expense and depreciation expense or principal repayments of ours, and to provide for the establishment and maintenance of reasonable financial reserves. Our Board sets our rates to our Class A and D Members at

a level intended to achieve and maintain “A” category credit ratings and otherwise to comply with our Indenture covenants and other contractual commitments.

These wholesale power contracts require our Board to review our rates at least annually and to revise such rates as necessary to produce revenue as described above. We provide all Class A Members between 30 and 45 days’ written notice of any rate schedule change. Changes to our rate schedule are generally not subject to the approval of the Rural Utilities Service (“RUS”). See [“MANAGEMENT’S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS—Key Factors Affecting Results,”](#) [“BUSINESS—Rates and Regulation”](#) and [“BUSINESS—Transmission Agreements and Coordination”](#) for a description of the regulation of our rates. See also [“LEGAL PROCEEDINGS”](#) for a description of existing proceedings relating to our rates to our Class A Members and prior regulation by the Federal Energy Regulatory Commission (“FERC”).

Corporate Information

Our principal office is located at 1717 East Interstate Avenue, Bismarck, North Dakota 58503-0564. Our telephone number is (701) 223-0441. Our website is www.basinelectric.com. Information on our website is not a part of this offering memorandum and is not incorporated herein by reference.

The Exchange Offer

On October 14, 2025, we completed the private offering of \$700,000,000 aggregate principal amount of 5.850% First Mortgage Obligations, 2025 Series A Bonds due 2055. As part of that issuance, we entered into an Exchange and Registration Rights Agreement, dated as of October 14, 2025 (the “Registration Rights Agreement”), with respect to the Original Bonds, with the initial purchasers in the private offering, in which we agreed, among other things, to deliver this prospectus to you and to use our reasonable commercial efforts to complete an exchange offer for the Original Bonds. Below is a summary of the Exchange Offer.

The Exchange Offer We are offering to exchange up to \$700,000,000 aggregate principal amount of outstanding Original Bonds for a like principal amount of Exchange Bonds. You may tender Original Bonds only in denominations of \$2,000 and any integral multiple of \$1,000 in excess of \$2,000. We will issue the Exchange Bonds promptly after the expiration of the Exchange Offer. In order to be exchanged, an Original Bond must be validly tendered, not validly withdrawn and accepted by us. Subject to the satisfaction or waiver of the conditions of the Exchange Offer, all Original Bonds that are validly tendered and not validly withdrawn will be accepted by us and exchanged. As of the date of this prospectus, \$700,000,000 aggregate principal amount of Original Bonds is outstanding. The Original Bonds were issued under our Amended and Restated Indenture, dated as of May 5, 2015 (as amended and supplemented, the “Indenture”), between Basin Electric and U.S. Bank Trust Company, National Association, as successor-in-interest to U.S. Bank National Association, as trustee (the “Trustee”), as supplemented by the Forty-Second Supplemental Indenture thereto, dated as of September 15, 2025 (the “Forty-Second Supplemental Indenture”). If all outstanding Original Bonds are validly tendered for exchange, there will be \$700,000,000 aggregate principal amount of Exchange Bonds outstanding after the Exchange Offer.

Purpose of the Exchange Offer The purpose of the Exchange Offer is to satisfy our obligations under the Registration Rights Agreement.

Expiration Date; Tenders	<p>The Exchange Offer will expire at 5:00 p.m., New York City time, on June 4, 2026, unless we extend the period of time during which the Exchange Offer is open. In the event of any material change to the Exchange Offer, we will extend the period of time during which the Exchange Offer is open as necessary. By signing or agreeing to be bound by the accompanying letter of transmittal, you will represent, among other things, that:</p> <ul style="list-style-type: none">• you are not an affiliate of ours or, if you are our affiliate, you will comply with the registration and prospectus delivery requirements of the Securities Act to the extent applicable in connection with the resale of the Exchange Bonds;• you are acquiring the Exchange Bonds in the ordinary course of your business;• you are not participating, do not intend to participate, and have no arrangement or understanding with anyone to participate, in the distribution (within the meaning of the Securities Act) of the Exchange Bonds;• you are not a broker-dealer that purchased any of the Original Bonds from us or any of our affiliates for resale pursuant to Rule 144A or any other available exemption under the Securities Act; and• if you are a broker-dealer that will receive Exchange Bonds for your own account in exchange for Original Bonds that were acquired by you as a result of market-making activities or other trading activities, you will deliver a prospectus (or to the extent permitted by law, make available a prospectus to purchasers) in connection with any resale of such Exchange Bonds. For further information regarding resales of the Exchange Bonds by broker-dealers, see the discussion under the caption "PLAN OF DISTRIBUTION."
Accrued Interest on Original Bonds	<p>Any interest that has accrued on an Original Bond before its exchange in the Exchange Offer will be payable on the Exchange Bond on the first interest payment date after the completion of the Exchange Offer.</p>
Conditions to the Exchange Offer	<p>Our obligation to accept Original Bonds tendered in the Exchange Offer is subject to the satisfaction of certain customary conditions. See "THE EXCHANGE OFFER—Conditions to the Exchange Offer."</p>

Procedures for Tendering Original Bonds	<p>A tendering holder must, prior to 5:00 p.m., New York City time, on the expiration date:</p> <ul style="list-style-type: none">• transmit a properly completed and duly executed letter of transmittal, including all other documents required by the letter of transmittal, to the Exchange Agent (as defined herein) at the address listed in this prospectus; or• if Original Bonds are tendered in accordance with the book-entry procedures described in this prospectus, the tendering holder must transmit an agent's message (as defined herein) to the Exchange Agent. <p>See "THE EXCHANGE OFFER—Procedures for Tendering."</p>
Special Procedures for Beneficial Holders	<p>If you are a beneficial holder of Original Bonds that are registered in the name of your broker, dealer, commercial bank, trust company or other nominee, and you wish to tender in the Exchange Offer, you should promptly contact the person in whose name your Original Bonds are registered and instruct that nominee to tender on your behalf. See "THE EXCHANGE OFFER—Procedures for Tendering."</p>
Withdrawal Rights	<p>Tenders may be withdrawn at any time before 5:00 p.m., New York City time, on the expiration date. See "THE EXCHANGE OFFER—Withdrawal Rights."</p>
Acceptance of Original Bonds and Delivery of Exchange Bonds	<p>Subject to the conditions stated in the section entitled "THE EXCHANGE OFFER—Conditions to the Exchange Offer" of this prospectus, we will accept for exchange any Original Bonds that are validly tendered in the Exchange Offer and not validly withdrawn before 5:00 p.m., New York City time, on the expiration date. The corresponding Exchange Bonds will be delivered promptly after the expiration date. See "THE EXCHANGE OFFER—Terms of the Exchange Offer."</p>
Absence of Dissenters' Rights of Appraisal	<p>Holders of Original Bonds do not have any dissenters' rights of appraisal with respect to the Exchange Offer. See "THE EXCHANGE OFFER—Absence of Dissenters' Rights of Appraisal."</p>
Certain U.S. Federal Income Tax Considerations	<p>An exchange of Original Bonds for Exchange Bonds pursuant to the Exchange Offer generally will not be treated as a taxable exchange for U.S. federal income tax purposes. See "CERTAIN U.S. FEDERAL INCOME TAX CONSIDERATIONS."</p>
Exchange Agent	<p>U.S. Bank Trust Company, National Association is serving as the exchange agent (the "Exchange Agent") in connection with the Exchange Offer. The address and telephone number of the Exchange Agent are listed under the heading "THE EXCHANGE OFFER—Exchange Agent."</p>
Use of Proceeds	<p>We will not receive any cash proceeds from the issuance of the Exchange Bonds in the Exchange Offer. The Original Bonds surrendered and exchanged for the Exchange Bonds will be retired and canceled. Accordingly, issuance of the Exchange Bonds will not result in any increase in our outstanding indebtedness.</p>

Resale of Exchange Bonds . Based on existing interpretations of the Securities Act by the SEC staff set forth in several no-action letters to third parties and subject to the immediately following sentence, we believe Exchange Bonds issued under this Exchange Offer in exchange for Original Bonds may be offered for resale, resold and otherwise transferred by the holders thereof (other than holders that are broker-dealers) without further compliance with the registration and prospectus delivery provisions of the Securities Act. However, any holder of Original Bonds that is an affiliate of ours that does not comply with the registration and prospectus delivery requirements of the Securities Act to the extent applicable in connection with the resale of the Exchange Bonds, that will not acquire the Exchange Bonds in the ordinary course of its business, or that intends to participate in the Exchange Offer for the purpose of distributing any of the Exchange Bonds, or any broker-dealer that purchased any of the Original Bonds from us or any of our affiliates for resale pursuant to Rule 144A or any other available exemption under the Securities Act, (i) will not be able to rely on the interpretations of the SEC staff set forth in the above-mentioned no-action letters, (ii) will not be entitled to tender its Original Bonds in the Exchange Offer and (iii) must comply with the registration and prospectus delivery requirements of the Securities Act in connection with any sale or transfer of the Original Bonds unless such sale or transfer is made pursuant to an exemption from such requirements.

Any broker-dealer that receives Exchange Bonds for its own account in exchange for Original Bonds that were acquired as a result of market-making activities or other trading activities, must deliver a prospectus (or to the extent permitted by law, make a prospectus available to purchasers) in connection with any resale of such Exchange Bonds. See "[PLAN OF DISTRIBUTION](#)."

Consequences of Not Exchanging Original Bonds

If you do not exchange your Original Bonds in the Exchange Offer, you will continue to be subject to the restrictions on transfer described in the legends on your Original Bonds. In general, you may offer or sell your Original Bonds only:

- if they are registered under the Securities Act and applicable state securities laws;
- if they are offered or sold pursuant to an exemption from registration under the Securities Act and applicable state securities laws; or
- if they are offered or sold in a transaction not subject to the Securities Act and applicable state securities laws.

Although your Original Bonds will continue to accrue interest, they will generally retain no rights under the Registration Rights Agreement. We currently do not intend to register the Original Bonds under the Securities Act. Under some circumstances, holders of the Original Bonds, including holders that are not permitted to participate in the Exchange Offer or that may not freely sell Exchange Bonds received in the Exchange Offer, may require us to file, and to cause to become effective, a shelf registration statement covering resales of Original Bonds by these holders. For more information regarding the consequences of not tendering your Original Bonds and our obligations to file a shelf registration statement, see [“THE EXCHANGE OFFER—Consequences of Exchanging or Failing to Exchange the Original Bonds”](#) and [“THE EXCHANGE OFFER—Registration Rights.”](#)

Risk Factors

See [“RISK FACTORS”](#) for a discussion of certain factors that you should carefully consider before deciding to participate in the Exchange Offer.

The Exchange Bonds

The summary below describes the principal terms of the Exchange Bonds. Certain of the terms and conditions described below are subject to important limitations and exceptions. The "[DESCRIPTION OF THE EXCHANGE BONDS](#)" section of this prospectus contains a more detailed description of the terms and conditions of the Exchange Bonds. In this summary, "Bonds" refers to both the Original Bonds and the Exchange Bonds.

Issuer	Basin Electric Power Cooperative
Bonds Offered	Up to \$700,000,000 aggregate principal amount of 5.850% First Mortgage Obligations, 2025 Series A Bonds due 2055. The terms of the Exchange Bonds are identical to the terms of the Original Bonds, except that the transfer restrictions, registration rights and additional interest provisions applicable to the Original Bonds do not apply to the Exchange Bonds.
Maturity Date	October 15, 2055.
Interest Rate and Payment ..	We will pay interest on the Exchange Bonds at the annual rate of 5.850%, based on a 360-day year of twelve 30-day months, from the last date on which interest was paid on the Original Bonds, payable semi-annually in arrears on April 15 and October 15 of each year.
Form and Denominations	The Exchange Bonds will be issued in global form in minimum denominations of \$2,000 and integral multiples of \$1,000 in excess thereof.
Ranking and Security for Payment	The Exchange Bonds will be secured equally and ratably with all our other Obligations issued under the Indenture by a mortgage lien on substantially all of our owned tangible and certain of our intangible properties, subject to certain exceptions and exclusions as described or referred to herein. As of December 31, 2025, we had approximately \$5.0 billion of Obligations outstanding under the Indenture. See " SUMMARY OF THE INDENTURE ."
Certain Covenants	The Indenture obligates us to establish and collect rates for the use or the sale of the output, capacity or service of our system that, together with all other revenue, are sufficient to enable us to comply with all of our covenants under the Indenture. Subject to any necessary regulatory approvals, the Indenture also requires us to establish and collect rates that, together with all other revenue, are reasonably expected to yield an MFI Ratio equal to at least 1.10 for each fiscal year. We were in compliance with the MFI Ratio requirement for 2025. See " SUMMARY OF THE INDENTURE—Certain Covenants ." In addition, the Indenture places certain restrictions on our ability to, among other things, make distributions, payments or retirements of patronage capital to our members, create liens or dispose of certain property subject to the lien thereof and engage in consolidations or mergers. See " SUMMARY OF THE INDENTURE—Certain Covenants ."

Optional Redemption At any time or from time to time before April 15, 2055 (the date that is six months prior to the maturity date of the Exchange Bonds), we may redeem the Exchange Bonds at our option, in whole or in part, at a “make whole” redemption price (expressed as a percentage of principal amount and rounded to three decimal places) equal to the greater of:

- (a) the sum of the present values of the remaining scheduled payments of principal and interest on the Exchange Bonds to be redeemed discounted to the redemption date (assuming the Exchange Bonds to be redeemed matured on April 15, 2055 (the date that is six months prior to the maturity date of the Exchange Bonds)) on a semi-annual basis (assuming a 360-day year consisting of twelve 30-day months) at the Treasury Rate (as defined in this prospectus) plus 20 basis points less
- (b) interest accrued on the Exchange Bonds to be redeemed to the date of redemption; and
- 100% of the principal amount of the Exchange Bonds to be redeemed;

plus, in either case, accrued and unpaid interest thereon, if any, to, but excluding, the redemption date.

At any time or from time to time on or after April 15, 2055 (the date that is six months prior to the maturity date of the Exchange Bonds), we may redeem the Exchange Bonds at our option, in whole or in part, at a redemption price equal to 100% of the aggregate principal amount of the Exchange Bonds being redeemed, plus accrued and unpaid interest thereon, if any, to, but excluding, the redemption date.

The Exchange Bonds will not be subject to repayment at the option of the holder at any time prior to maturity.

See [“DESCRIPTION OF THE EXCHANGE BONDS—Optional Redemption.”](#)

Absence of an Established Market for the Bonds We do not intend to apply for a listing of the Exchange Bonds on any securities exchange or any automated dealer quotation system. Although certain dealers currently make a market in the Original Bonds, and we expect that such market-making activities will extend to the Exchange Bonds, they are not obligated to do so, and may discontinue market-making activities in the Bonds at any time without notice. Accordingly, we cannot assure you that a liquid market for the Exchange Bonds will develop or be maintained.

Trustee and Registrar U.S. Bank Trust Company, National Association, as successor-in-interest to U.S. Bank National Association.

Risk Factors See [“RISK FACTORS”](#) for a discussion of certain factors that you should carefully consider before investing in the Exchange Bonds.

SUMMARY CONSOLIDATED FINANCIAL DATA

The following financial data presents historical information relating to our financial condition and results of operations as of the dates and for the periods presented. Summary financial data as of December 31, 2025 and 2024, and for the years ended December 31, 2025, 2024, and 2023 that are presented below were derived from our audited consolidated financial statements. Prospective investors should read the summary financial data below in conjunction with [“CAPITALIZATION”](#) and [“MANAGEMENT’S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS”](#) in addition to the consolidated financial statements included in this prospectus.

(in thousands)	Years Ended December 31,		
	2025	2024	2023
Income Statement Data:			
Operating revenue	\$ 3,087,771	\$ 2,815,399	\$ 2,887,118
Operating expenses	2,867,378	2,639,824	2,577,431
Operating margin	220,393	175,575	309,687
Other income	203,270	220,239	108,408
Interest and other charges	277,861	264,857	255,703
Margin before income taxes	145,802	130,957	162,392
Income tax expense (benefit)	6,530	(13,037)	(6,207)
Net margin and earnings including noncontrolling interest	139,272	143,994	168,599
Net margin and earnings attributable to noncontrolling interest	(23,000)	(23,215)	(21,083)
Net margin and earnings attributable to Basin Electric	<u>\$ 116,272</u>	<u>\$ 120,779</u>	<u>\$ 147,516</u>

(in thousands)	As of December 31,	
	2025	2024
Balance Sheet Data:		
Assets:		
Net property, plant and equipment	\$ 6,655,619	\$ 6,060,620
Total assets	\$ 9,397,657	\$ 8,494,782
Capitalization and liabilities:		
Capitalization:		
Equity:		
Memberships	\$ 22	\$ 22
Patronage capital	1,523,238	1,476,557
Retained earnings of subsidiaries	142,776	125,713
Other equity	294,252	285,113
Accumulated other comprehensive income	13,463	4,806
	<u>1,973,751</u>	<u>1,892,211</u>
Noncontrolling interest	2,676	2,711
Total Equity	<u>1,976,427</u>	<u>1,894,922</u>
Long-term debt and finance lease obligations	4,952,796	4,592,678
Total capitalization	<u>6,929,223</u>	<u>6,487,600</u>
Current liabilities	1,429,804	997,777
Deferred credits and other	1,038,630	1,009,405
Total Capitalization and Liabilities	<u>\$ 9,397,657</u>	<u>\$ 8,494,782</u>

RISK FACTORS

Investing in the Exchange Bonds involves risks. The following discussion reflects our beliefs and opinions as to risks and uncertainties that could affect our business, results of operations, financial condition or payments to be made with respect to the Exchange Bonds, or all of the above. This discussion is not exhaustive, should be read in conjunction with all other parts of this prospectus and should not be considered a complete description of all risks that could affect our business, payments on the Exchange Bonds, or both. References to past events are provided by way of example only and are not intended to be a complete listing or a representation as to whether or not such factors have occurred in the past or their likelihood of occurring in the future. Additional risks and uncertainties not presently known to us or that we currently deem immaterial may also impair our business operations. If any of those risks actually occurs, our business, results of operations or financial condition could suffer. You should analyze carefully the information contained in this prospectus when evaluating whether to participate in the Exchange Offer. The risks discussed below also include forward-looking statements and our actual results may differ substantially from those discussed in these forward-looking statements. See “[FORWARD-LOOKING STATEMENTS](#)” in this prospectus.

Financial Risks

Our results of operations and financial condition are largely dependent upon our Class A Members, and two Class A Members individually account for more than 10% of our total Class A Member revenue.

Our results of operations and financial condition depend on our Class A Members to satisfy their obligations to us in accordance with our wholesale power contracts with them. Electric sales to our Class A Members provided approximately 90.5% of our 2025 electric sales revenue. Upper Missouri Power Cooperative (“Upper Missouri”) and East River Electric Power Cooperative (“East River”) accounted for 42.7% and 12.8%, respectively, of our total Class A Member revenue in 2025. If one or more of our Class A Members were to default in the performance of its obligations to us under their wholesale power contract, our results of operations or cash flows could be adversely affected.

Most of our wholesale power contracts with our Class A Members extend beyond the maturity of the Bonds; however, our wholesale power contracts with Tri-State, Minnesota Valley, Wright-Hennepin and WMPA only extend through 2050, prior to maturity of the Bonds. These members represented in the aggregate approximately 10.1% of 2025 Class A Member sales. There cannot be any assurance that our wholesale power contracts with these Class A Members will be extended or replaced prior to the expiration of these contracts. See “[BUSINESS—Wholesale Power Contracts](#).”

Financial difficulties, such as those resulting from challenges in passing through its costs to its customers, could affect a member’s ability to perform its obligations under its wholesale power contract with us. Such challenges could arise from the failure of the member’s board of directors to establish rates and charges sufficient to recover the member’s costs, including power costs owed to us. If our cost of power were to become uncompetitive, large industrial customers of our Class A Members could seek to self-generate their power requirements or customers of the members could seek to cause our members to become subject to state rate regulation. Certain of our members, such as those located in Wyoming, are already subject to rate regulation by state regulatory authorities. New or additional state-level rate regulation of a member could potentially affect its ability to recover costs and meet its obligations to us. We cannot predict if or when any such state-level rate regulation will be implemented in the future in other states within our service territory or what the impact of future state-level rate regulation may be. To date, however, such state-level rate regulation has not prevented affected members from being able to recover their costs.

We have a substantial amount of indebtedness and expect to incur significant future capital expenditures. Constraints on our access to, or increases in our cost of, capital could adversely affect our results of operations and financial condition.

Our substantial existing indebtedness and the significant capital expenditures planned through 2030 to construct, acquire, and make capital improvements to our generation and transmission facilities will require our continued access to the capital markets. As of December 31, 2025, we had total debt outstanding of approximately \$5.8 billion. In the years 2026 through 2030, we forecast that we will invest approximately \$7.5 billion in capital expenditures for the development and construction of new generation and transmission resources to serve existing and projected load growth and upgrades to our existing facilities. The scope and timing of these investments are subject to numerous uncertainties, including the forecasted electric demand of our members; the availability and cost of available power purchase options; our membership in regional transmission organizations and their applicable tariffs and policies; federal funding; and regulatory approvals and changes in law. For additional information, see the discussion under the caption "Projected Capital Expenditures" in "[MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS.](#)"

We expect to incur significant indebtedness to fund this capital expenditure program. Failure to obtain financing may adversely affect our results of operations, liquidity and financial condition, and may result in development uncertainties for our generation and transmission business. Although we plan on exploring additional financing of projects from RUS, our ability to receive any such financing could be impacted by the terms set by RUS and, because RUS funding availability is dependent on Congressional appropriation, competition for RUS loans from other electric cooperatives may exceed available funds. In addition, a significant increase in our indebtedness is likely to increase the cost of electric service we provide to our Class A Members due to increasing interest expense as well as our objective to maintain "A" category credit ratings. If demand for electricity from our Class A Members is materially less than projected, we might not generate sufficient revenue to meet the MFI Ratio requirements in the Indenture or to service our indebtedness. If this occurs, we may be required to raise our rates, revise our plans for capital expenditures or restructure our long-term commitments. These actions may adversely affect our operations, and we may be unable to generate sufficient additional revenue to pay our obligations.

We also rely on access to short-term and long-term capital to meet our liquidity needs not funded by operating cash flows. Our access to capital, or cost of, could be adversely affected by various factors, and some market disruptions could constrain, at least temporarily, our ability to maintain sufficient liquidity and access capital on favorable terms, or at all. These factors and disruptions include:

- our credit ratings being downgraded;
- financial markets view of our relationship with our members, including the outcome of litigation or regulatory proceedings;
- challenges or delays related to rate changes for our Class A Members; and
- some of the wholesale power contracts with our Class A Members only extending through 2050.

Broader economic and market conditions that may affect our access to, or cost of, capital include:

- geopolitical instability, economic downturns or market uncertainty;
- market pressures, including tightening of lending standards by commercial banks and other credit providers;
- changes in prevailing interest rates due to changes in U.S. Treasury rates or credit spreads; and
- conditions in the energy industry and the generation and transmission cooperative sector.

Even if we maintain access to the capital markets, capital may only be available on terms and conditions we consider unfavorable, including higher interest rates or more restrictive covenants and conditions to borrowing or events of defaults. If our ability to access capital becomes constrained, our ability to finance capital expenditures could be limited, our interest costs could increase, and our results of operations and financial condition could be adversely affected.

The financial performance of our subsidiary, Dakota Gas, has a significant impact on our financial results and its future is uncertain. We continue to explore strategic alternatives and some of the alternatives could result in substantial costs or may result in an asset impairment.

Our consolidated financial results are significantly affected by the performance of Dakota Gas, in which the Gasification operating segment accounted for 16.0% of our consolidated revenue in 2025. As of December 31, 2025, none of our equity represented retained earnings of Dakota Gas and our Gasification segment incurred net losses of \$34.8 million and \$31.3 million for the years ended December 31, 2025 and 2024, respectively. Historically, we have benefited from synergies with Dakota Gas, including economies of scale resulting from a shared coal supply that lowers our fuel cost and various shared services. Additionally, because Dakota Gas produces and sells natural gas and we purchase natural gas for electric generation, its natural gas sales offset part of the risk associated with our natural gas purchases, creating a natural hedge. Dakota Gas's financial performance remains exposed to significant commodity price volatility, and operating losses and negative cash flows could continue if commodity prices remain low.

We continue to evaluate various strategic options, including a potential sale of the equity or assets of Dakota Gas, in whole or in part. Dakota Gas's principal assets include the Synfuels Plant and pipelines currently used to transport carbon dioxide into Canada. There is no assurance that any transaction will occur. A sale or other strategic action could result in the loss of existing synergies with Dakota Gas. Decommissioning or repurposing the Synfuels Plant could require substantial costs including site reclamation, employee severances and the loss of our above-described synergies with Dakota Gas.

The nature and extent of risks associated with the future of Dakota Gas and its assets cannot be fully predicted and events relating to the Synfuels Plant may affect us in ways that we cannot currently anticipate. Although the value of the coal gasification assets of the Synfuels Plant has been written off, we could incur additional impairment charges related to our remaining non-coal gasification assets investments in Dakota Gas. If an impairment occurs, we expect that we would seek regulatory accounting treatment from RUS to amortize the resulting regulatory asset over a future period. Failure to receive such regulatory accounting treatment could materially adversely affect our results of operations, financial condition and cash flows. See [“MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS—Key Factors Affecting Results—Future of Dakota Gas.”](#)

Any one or a combination of risks associated with Dakota Gas may have a material adverse effect on our results of operations, financial condition and cash flows.

Changes in commodity prices, including natural gas, coal, purchased power, and fertilizers and other products produced by Dakota Gas, could adversely affect our cost of electric service and Dakota Gas revenue.

We purchase power and fuel from other suppliers exposing us to market prices of various commodities that could increase our operating expenses. In 2025, natural gas units comprised approximately 20.0% of our maximum winter generating capacity. With the addition of Bison Generating Station, we forecast that in 2031 this amount will increase to approximately 35.0%. Historically, Dakota Gas has provided a natural hedge for us against price fluctuations of natural gas. However, as we add additional natural gas generation, we expect to burn more natural gas annually than what Dakota Gas produces and the value of this natural hedge may decrease. There can be significant volatility in market prices for fuel, power and other energy-related commodities, both in general and across geographies, because of broader supply chain challenges, geopolitical events or conflicts, and commodity availability

constraints. Natural gas supplies may also be unavailable due to increased demand during periods of exceptionally cold weather and are also subject to disruption due to natural disasters and similar events or infrastructure failure. Further, purchasing electric power in the market exposes us, and consequently our members, to market price risk because electric power prices can fluctuate substantially over short periods of time. Increases in power and fuel prices related to natural gas or coal could significantly increase the cost of electric service we provide to our Class A Members and affect their ability to perform their contractual obligations to us.

Although our hedging activities help reduce some market price risk, Dakota Gas remains exposed to volatile commodity prices which could result in future losses. See also [“QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK.”](#) Additionally, Dakota Gas’s products also are exposed to market risks other than pricing, particularly in the agricultural sector. Economic conditions in the agricultural sector directly influence demand for fertilizers, such as anhydrous ammonia, ammonium sulfate and urea, exposing Dakota Gas’s revenues to downturns in this sector. Further, most market price risks related to products other than natural gas and tar oil cannot be hedged because no efficient derivative market exists for these commodities. As a result, changes in natural gas, fertilizer, and other commodity prices could adversely affect our results of operations and financial condition.

Market or regulatory pressures may cause us to retire our coal-fired generating facilities earlier than the units’ depreciable lives, which could result in substantial additional costs.

As of December 31, 2025, our coal-fired electric generation facilities totaled approximately \$2.0 billion of our net assets. We own, lease and operate coal-fired generating facilities with 3,665 MW of capacity as of December 31, 2025. Early retirement of these facilities could lead to substantial expenses, including accelerated depreciation, increased purchased power and capacity costs, or significant capital investments to replace lost capacity or repurpose existing facilities. Early retirement of these facilities could also create stranded assets unless we obtain regulatory accounting treatment approval from RUS to establish a regulatory asset to recover related costs over time. Without such approval, we could face substantial impairments to our members’ patronage capital and other equities. Even with regulatory accounting treatment, amortization of these costs may require rate increases that could reduce the competitiveness of our service.

Early retirement would also accelerate reclamation and mine-related obligations, increasing both the timing and total amount of these costs. In addition, we could incur severance obligations for employees at the facilities and associated mines, as well as significant termination charges under take-or-pay transportation contracts.

Our costs for future capital expenditures may be adversely affected by unanticipated higher levels of inflation, increasing labor costs and shortages, implementation of tariffs, and other supply chain disruptions.

Our ability to meet our Class A Members’ electric power requirements and complete our capital projects is dependent on maintaining an efficient supply chain and controlling our costs, including labor, material and financing costs. We are experiencing longer lead-times on the procurement and delivery of some materials and equipment, which have been impacted by domestic and global supply chain disruptions. Additionally, inflation has contributed to lingering high prices for materials and equipment and increases in labor costs to retain sufficient labor resources. Imposed and proposed tariffs could significantly increase the prices and delivery lead times on materials and equipment critical to completing our capital projects.

We are exposed to the credit and liquidity risk of and with counterparties beyond our Class A Members.

In addition to our Class A Members, we are exposed to the risk that contractual counterparties will default in the performance of their obligations to us. We regularly analyze and monitor the default risks of counterparties and other credit issues related to our material contracts. Based on our review, we may

require counterparties to post credit support. Still, defaults may occur. Defaults may take the form of failure to physically deliver purchased goods or supplies, such as power or natural gas. If a default occurs, we may be forced to enter into alternate contractual arrangements at prices that may be less favorable than those in the original contracts. If a defaulting counterparty is in poor financial condition, we may not be able to recover damages for breach of contract.

Dakota Gas also has exposure to the credit risk of its counterparties. Several byproducts produced at the Synfuels Plant have a small number of potential purchasers. Evaluation of these purchasers' respective credit quality is impaired by the limited availability of independent financial information and analysis for these entities. A contractual counterparty may fail to perform its obligations to Dakota Gas, which could adversely affect our consolidated results of operations, financial condition or cash flows.

Additionally, certain of our financial agreements and commercial contracts include collateral and termination triggers that may be active if credit metrics fall below specified levels and may require posting of collateral (in the form of letters of credit, surety bonds or cash) or termination of the agreements, which could adversely affect our results of operations, financial condition, or cash flows, as well as our ability to enter into future financial agreements and commercial contracts.

The use of hedging arrangements may not work as planned or fully protect us and could result in financial losses and requirements to post collateral.

We typically enter into hedging arrangements, including contracts to purchase or sell commodities at future dates and at fixed prices, in order to manage our commodity price risks. These activities, although intended to mitigate price volatility, expose us to risks related to commodity price movements and other risks. When we purchase or sell commodities forward, we may be required to post significant amounts of cash collateral or other credit support to our counterparties if forward prices move unfavorably to our position. Further, if forward price curves move unfavorably to our position the values of financial contracts may deteriorate and could result in adverse effects to our results of operations, financial condition, or cash flows. We also employ risk management techniques to hedge against interest rate volatility. However, significant and sustained volatility in market interest rates could still materially increase our financing costs and adversely affect our results of operations, cash flows and liquidity.

We maintain internal policies and procedures intended to govern hedging activities, including limits on positions and a prohibition on speculative trading. While these policies and procedures are designed to prevent hedging arrangements in excess of desired limits or unauthorized hedging transactions, they may not detect all violations, particularly in instances involving intentional misconduct or deception. Any failure of our risk-management controls or processes could result in unintended positions, financial losses, or other adverse effects on our results of operations, financial condition, or cash flows.

The scope or amount of our insurance coverage may be insufficient.

We maintain a comprehensive insurance and self-insurance program to provide coverage for various types of risks, including severe weather or other natural disasters, wildfires, property damage, war, terrorism, cyber incidents, liability claims against us, or a combination of other significant unforeseen events that could affect our operations. However, insurance coverage may not continue to be available or may not be available at rates or on terms similar to those presently available to us. Our ability to obtain insurance and the terms of any available insurance coverage could be adversely affected by the financial condition of insurers, industry losses, the impacts of actual or perceived climate-related events, as well as international, national, state, local or business-specific events. There may be some instances in which we are not fully insured against all significant losses. A loss for which we are not fully insured could have an adverse effect on our business, results of operations, financial condition and prospects. If the amount of insurance is insufficient or otherwise unavailable, the costs of uninsured losses, our results of operations, financial condition or cash flows could be adversely affected.

Operating Risks

Factors outside our control could disrupt our power supply plans.

We are focused on reliably and economically meeting our members' requirements for electric power. We continually evaluate and refine our power supply strategy to achieve this objective in a manner that balances the forecasted cost of power to our members, our ability to provide reliable service and our impact on the environment. Based on our strategy, we develop and construct new generation and transmission facilities and enter into long-term and short-term power purchase agreements. In developing and implementing our strategy, we are guided by our forecasts of future market conditions and our assessment of the likelihood of the occurrence of various contingencies. Some of these contingencies include:

- Future market prices for natural gas and electricity;
- Current and future transmission constraints and changes in the location of load impacting the ability to deliver electricity to desired locations; and
- Trends in the rate of installation of renewable energy resources, such as wind-powered generation facilities and energy storage, in the service territories of our members and neighboring regions.

As with any forecast, our ability to accurately predict or anticipate future events becomes less reliable the farther into the future the forecast extends. We must make assumptions to develop our plans for the future. These assumptions include economic forecasts, cost estimates, construction schedules, power demand forecasts, reliability and reserve margin requirements, the appropriate generation mix to meet demand and potential changes to the regulatory environment. Should our assumptions be inaccurate, or be superseded by subsequent events, or unexpected contingencies occur, our plans may not be effective in achieving the intended results, which could adversely affect our results of operations, financial condition or cash flows, our ability to meet electricity demand, or the way we conduct our business.

Our ability to successfully develop and execute our power supply strategy for our members is complicated by the need to serve load in both the Eastern Interconnection and the Western Interconnection of the United States and the need to balance our members' requirements in several transmission systems. See "[BUSINESS—Transmission](#)." For example, a surplus of generating capacity located in MISO may not easily be used to meet additional load in SPP. A surplus of transmission capacity may also exist in one system, while transmission constraints requiring significant investment may exist in another system. Consequently, even if our power supply portfolio includes the right mix of resources, those resources may not be optimally located for efficient use as the grid continually evolves.

Failure of our facilities to operate as we plan could have an adverse effect on our results of operations or financial condition.

The operation of our generation or transmission facilities involves risks, including the breakdown or failure of power generation equipment, transmission lines, pipes or other equipment or processes and performance below expected levels of output or efficiency. The occurrence of any such events could result in:

- Loss of market sale opportunities;
- Significant expenditures to repair or replace the affected facilities or related infrastructure;
- Failure to maintain the integrity or reliability of our transmission system; or
- Increases in purchased power.

In the Eastern energy markets of SPP and MISO, failure of our facilities to operate as planned could also result in:

- Loss of capacity accreditation, requiring the purchase of additional market capacity and potentially resulting in deficiency payments under applicable market rules;
- Increase in market pricing, if the unit in outage is the marginal unit or affects the pricing of the marginal unit;
- Increase in market pricing if a transmission outage or changes in load or generation resources drives an increase in congestion costs; or
- Financial implications of not providing MWhs to the market, if a unit has committed MWhs in the day-ahead market and cannot provide that energy in real time.

In Western markets of the Western Electricity Coordinating Council (“WECC”), failure of our facilities to operate as planned could result in:

- The need to operate alternative facilities for an extended period of time, likely at a greater cost;
- A default on a contractual obligation to deliver power; or
- The purchase of potentially more costly replacement energy and capacity power in the market.

In addition, the failure of our generation, transmission or other facilities to perform as planned may cause health, safety or environmental problems. Our ability to safely and reliably operate, maintain and construct our facilities is subject to numerous risks, many of which are beyond our control, including:

- The failure to take timely or adequate action to mitigate identified unsafe conditions, resulting in a catastrophic event; or
- Operator or other human error.

If one or more of these events materialized, our results of operations, financial condition, or cash flows could be adversely affected.

We are subject to construction risks for additional projects we are undertaking to meet projected load growth.

In 2026 through 2030, we expect to spend approximately \$7.5 billion on additional capital expenditures on a consolidated basis. Our capital plan includes construction of new generation resources and a number of new transmission lines and facilities. See [“MANAGEMENT’S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS—Liquidity and Capital Resources—Projected Capital Expenditures”](#) for a description of our capital plan for additional electric generation and transmission facilities and capital for enhancement of existing facilities.

Our development and construction of new generation and transmission resources is subject to construction risk. We will also be subject to construction risks for capital projects to comply with current or future environmental standards. Many factors could lead to cost increases, cost overruns, and schedule delays for any of these projects, including:

- challenges related to the failure of contractors, subcontractors, or vendors to perform their obligations;
- timing and issuance of necessary permits, licenses, or approvals (including required certificates from regulatory agencies) and any related litigation or stakeholder opposition;
- unforeseen engineering problems or scope changes;

- performance under construction and equipment agreements and contract disputes;
- environmental litigation; and
- environmental, cultural, geological, and weather conditions.

Construction-related inflation, labor availability, supply chain disruptions, and tariff impacts may also contribute to project cost or schedule risk as discussed elsewhere in this “[RISK FACTORS](#)” section. Failure to complete any construction project on schedule and on budget for any reason could have an adverse effect on our results of operations.

Our members’ requirements are impacted by matters outside our control, including the power requirements in the Bakken shale formation and the operation of data centers.

In addition to the structure and nature of our power supply resources, our members’ requirements for power can significantly impact our results of operations, financial condition and cash flows. We currently forecast that our members’ peak demand requirements supplied by us will increase at an average annual compound rate of 2.5% for the period from 2026 through 2031, exclusive of large loads. Our forecasts of our members’ requirements and their actual future requirements may vary significantly. If we overestimate the growth in our members’ requirements, there is no assurance that the price of surplus capacity or energy from surplus power supply resources will be economical or could be sold without a loss. In addition, costs related to any new facilities constructed to meet the anticipated load growth could increase some of these members’ cost of electric service more than anticipated and could affect their ability to perform their contractual obligations to us. If we underestimate the growth in our members’ requirements, we may be required to purchase capacity or energy at a cost substantially above the cost we would have incurred to obtain the power or generate the energy from facilities we own.

Several factors could influence the actual rate of growth of our members’ requirements, including:

- The power requirements of our members serving commercial and industrial loads, including the Bakken shale formation and the operation of data centers to meet the increased demand for artificial intelligence (“AI”) resources as described below;
- Agricultural commodity price fluctuations and possible diseases that cause disruption in the food supply chain;
- Volatile pricing in the crypto currency markets that results in loads being curtailed or ramped up unexpectedly;
- The impact of extended periods of unusual or extreme weather on power requirements;
- Changes in trends “behind the meter,” such as growth in the use of distributed solar generation equipment and energy storage that reduce energy purchases from our members and thus us;
- Implementation of energy conservation and demand response programs that reduce peak demand; and
- Macroeconomic conditions in the members’ service territories, including population or economic changes.

Currently, one of the largest factors affecting the rate of growth of our members’ power requirements is economic activity related to oil and natural gas production in the Bakken shale formation in western North Dakota and eastern Montana. While the rate of growth of power requirements associated with oil production in the Bakken has moderated in recent years, growth still continues. Many factors impact oil and natural gas production in this region. One factor is the volatility of crude oil and natural gas prices. A significant decline in the price of crude oil and natural gas could impact the development of this region.

Therefore, the estimates as to the production volumes in the region could be too high and, as a result, our members' requirements for power could be impacted.

Due to the depth of the oil and natural gas, production from this formation requires fracking to separate the oil from the rock formation. To the extent that production of oil and natural gas by hydraulic fracking becomes more regulated by state or federal governments, production could be restricted or become more expensive, thereby impacting our Class A Members' load growth. Over the past decade, there has been an increase in the number of regulations and restrictions on the production of oil and natural gas through hydraulic fracking, including several states banning the practice entirely. Currently, the majority of the oil and natural gas recovered in our Class A Members' service territories are recovered utilizing hydraulic fracking. While we do not currently anticipate any regulations, restrictions or bans on fracking in the areas in which we operate, any regulation, restriction or ban by federal, state or local governments on fracking in those areas could adversely affect our results of operations, financial condition or cash flows and the way we operate our business.

Substantially large loads considered for development in the service territories of our Class A Members could significantly impact our Class A Members' requirements for power and our results of operations.

We are projected to experience significant load growth over the next several years resulting from traditional load growth and the development of several large commercial projects, including AI resources, data centers and cryptocurrency mining. Our members have received requests to commit to provide thousands of megawatts of baseload energy to new large loads. Both the number and size of these large load requests that are being considered for development and construction in the service territories of our members are increasing and expected to further increase substantially with the growth of AI and other factors, thereby potentially materially increasing the aggregate power requirements of our members. The volume of these large load requests and uncertainty related to these requests create risks.

To the extent that any of our members serve large data centers, serving this additional load growth may put pressure on our existing generation and transmission infrastructure and will require significant investments to meet the anticipated load growth and they will be subject to increased counterparty risk to customers that may consume a disproportionate percentage of their sales. Changes in technology could impact the development and continued resource needs of data centers and any significant decrease in those needs could affect the counterparty's willingness or ability to pay for large amounts of electricity. Cryptocurrency data mining centers' energy demands are particularly unpredictable as they may be affected by federal or state regulatory actions and are highly incentivized to operate in regions with relatively low energy prices and are able to shut down and relocate relatively easily. The potential volatility in energy demands from our Class A Members from these operations can exacerbate the challenges in determining our long-term power supply requirements and potentially adversely impact our financial results.

To meet the obligation to serve these large loads, insulate our existing membership from rate pressure associated with new generation and transmission requirements, increased fuel costs, and higher Locational Marginal Pricing ("LMP"), and to protect our balance sheet from stranded asset risk, we adopted a Large Load Commercial Program in 2025. Under this program, new loads meeting the requirements to be considered a "large load" will be billed under a rate structure that includes a market pass-through component and will be required to contribute a substantial portion of the capital required to build or acquire the assets necessary to serve their load. There is no guarantee that this program will fully insulate us from the risks associated with these large loads.

We cannot predict whether the large loads under consideration and for which we are planning will ever commence operations, the size and duration of the power requirements of those that do become operational, and whether they will seek to be served by a power supplier other than our members. For these and other reasons, there can be no assurance that these developments will not have an adverse effect on our business, results of operations, financial condition or cash flows.

If we are unable to obtain an adequate supply of fuel, our ability to operate our facilities could be limited.

We obtain our natural gas and coal from multiple suppliers. Any disruptions in our fuel supplies, could result in us having insufficient levels of fuel supplies. Natural gas and coal markets have experienced supply chain and availability constraints in recent years. Natural gas supplies may be limited during periods of seasonal demands and are also subject to disruption due to natural disasters and similar events or infrastructure failures. Any failure to maintain access to or an adequate inventory of fuel supplies could require us to operate other generating plants at a higher cost or require us to purchase higher-cost energy from other sources and, as a result, have an adverse effect on our results of operations, financial performance, or cash flows.

Our service reliability could be affected by problems at other utilities or by the increase in intermittent sources of power.

We are a transmission-owning member of SPP, a regional transmission organization. Some of our Class A Members also are transmission-owning members of SPP. In addition, some of our Class A Members service areas are within MISO and the WECC. SPP coordinates, controls and monitors the bulk electric system and wholesale power market in the central United States on behalf of a diverse group of utilities and transmission companies in fourteen states. Our transmission facilities are directly interconnected with the transmission facilities of neighboring utilities and are thus part of the larger bulk electric transmission system. Generation and transmission assets are the cornerstone of bulk electric system reliability. Accordingly, problems or outages at other utilities may increase costs, interrupt service to our members, or reduce service reliability. In addition, the increasing contribution of intermittent sources of power, such as wind and solar, may place significant strain on the entire bulk electric system, particularly if investment, operations, and maintenance of firm dispatchable generation units (e.g., coal or natural gas-fired generation facilities) sources are uneconomic. Greater curtailment or cycling of firm dispatchable generation may increase the wear-and-tear on these facilities and consequently increases the potential for breakdown of the facilities. If we suffer a service interruption, or the bulk electric system generally has reduced service reliability, our results of operations, financial condition, cash flows, or reputation may be adversely affected.

Wildfires and other catastrophic events could adversely affect our financial condition and results of operations.

We are exposed to the risk of wildfires and other catastrophic events that could result in substantial losses, operational disruptions, and significant financial impacts. We own over 2,500 miles of transmission lines as of December 31, 2025, including transmission lines that cross through certain wildfire-prone areas, such as forest areas and grasslands. Climate-related factors may worsen hot and dry summer conditions, which could increase the likelihood and magnitude of damages caused by fires burning or allegedly originating from our equipment. If a wildfire alleged to have involved our transmission facilities, or alleged to have resulted from our or our contractors' operating or maintenance practices, were to occur, we could be exposed to claims for property damage, costs of fire-fighting, evacuation, and clean-up activities, personal injury or loss of life, environmental pollution and other costs, for which liability could be substantial and in excess of our insurance coverage. We may also be subject to credit ratings downgrades, unfavorable media coverage, fines and penalties, or other negative consequences which may impact our financial condition and future plans. Any such liability could adversely affect us and our results of operations, financial condition, or cash flows.

In addition to wildfires, our operations may be affected by other catastrophic events, including tornadoes, floods, droughts, mechanical failures, and intentional acts such as terrorism. The frequency and severity of these events are unpredictable and may increase as a result of climate-related factors. Such events may damage critical infrastructure, disrupt our ability to generate or transmit electricity, impair fuel delivery and supply chains, or reduce our members' electricity requirements for an extended period. Restoration of damaged facilities may require substantial capital expenditures for repairs,

replacements, or modifications. Any resulting operational disruptions or financial impacts could be significant and could adversely affect our results of operations, financial condition, or cash flows.

We are subject to operational and market risks associated with participation in RTOs, including SPP and MISO.

Our operations within RTOs, including SPP and MISO, expose us to a variety of operational, regulatory, and market risks that could adversely affect our financial condition and results of operations. Both SPP and MISO have recently revised their planning reserve margin (“PRM”) requirements in response to increasing reliability concerns. In 2025, MISO reduced its PRM target from 9.0% to 7.9% for the 2025/2026 planning year, yet still experienced a 43% drop in surplus capacity compared to the prior year. This tightening of capacity positions, combined with the retirement of dispatchable generation and delays in new resource development, has led to significantly higher prices for capacity that we must purchase or have available. Similarly, SPP has approved and implemented an increase in its PRM from 15% to 16% for the summer season beginning in 2026, and has implemented a 36% PRM for the winter season starting in 2026/2027. These changes reflect the growing risk of winter reliability events, as recent studies show that the majority of annual loss-of-load risk is now concentrated in the winter months. As of April 1, 2026, we have transitioned portions of our western load and generation into a regional transmission organization and new balancing authorities, including SPP RTO West and the Black Hills and Public Service Company of Colorado (“PSCo”) balancing authorities. We also plan to further transition portions of our operations into additional organized wholesale markets during 2026, which could expose us to additional operational, regulatory, or market risks. These evolving market and reliability requirements may increase our cost of compliance, could limit our ability to take planned outages, and may require additional investment in capacity resources. Moreover, the variability of renewable generation, fuel supply constraints, and extreme weather events further complicate our ability to meet these requirements reliably. Failure to effectively manage these risks could adversely affect our results of operations, financial condition, or cash flows.

Failure to maintain a skilled workforce could adversely affect our operations.

Together with our subsidiaries, we require skilled executive officers as well as professional and technical employees to operate and maintain our generation, transmission and other facilities, such as the Synfuels Plant. Competition for qualified employees and broader labor shortages have made it more difficult to attract necessary personnel. Our failure to attract and retain the appropriate workforce talent required for the most efficient operation of our facilities and business could limit our ability to maximize our enterprise value.

A significant portion of our employees is covered by collective bargaining agreements with expiration dates ranging from 2026 through 2028. One collective bargaining agreement, representing employees at two generating stations, expired in 2024. This agreement is currently in arbitration, and we have not yet reached agreement on renewal. Failure to reach satisfactory agreements with these labor unions, or any resulting strikes, work stoppages, or other labor disruptions, could adversely impact our operations, financial condition, or results of operations. The terms of future collective bargaining agreements may also increase labor costs or limit our operational flexibility.

Legal and Regulatory Risks

We are involved in disputes and legal proceedings that, if determined unfavorably to us, could have an adverse effect on our results of operations, financial condition, or cash flows.

We are involved in several disputes and legal proceedings that, if determined unfavorably to us, could have a material adverse effect upon our business. See “[LEGAL PROCEEDINGS](#).” Any such disputes or legal proceedings, whether with or without merit, could be expensive and time consuming, could divert the attention of our management and, if resolved adversely to us, could harm our reputation and increase our costs or reduce our revenues, all of which could have a material adverse effect on our financial results.

Further, any adverse result to us with respect to our current disputes or legal proceedings could result in more litigation, further exacerbating the adverse consequences noted above.

Our business is the focus of extensive existing and proposed statutory and regulatory restrictions intended to limit the impact of our operations on the environment. These restrictions will impact our operations in ways we cannot fully predict and could have an adverse effect on our financial results.

We are required to comply with numerous federal, state and local laws relating to the protection of the environment. These laws include restrictions on air emissions, water discharges and the use, management and disposal of hazardous and solid wastes. We expect to spend substantial amounts on capital expenditures to comply with environmental laws, including for the installation, maintenance and operation of pollution control equipment, monitoring systems and other related equipment and facilities to comply with these laws.

Our ability to plan for and meet applicable environmental requirements is challenged due to new legislation, rulemaking, executive orders, and judicial interpretations with respect to environmental laws. The outcomes and effects of the United States Environmental Protection Agency's ("EPA") and other agencies' rulemakings, and of litigation, executive orders, and other governmental actions, cannot be predicted. Environmental regulations and orders sometimes are appealed or otherwise litigated in the courts for several years. Sometimes regulations or orders are vacated or stayed. Implementation of these contested laws, regulations, or proposals can be delayed. In addition, there may be attempts to repeal or amend final regulations that have survived legal challenges and become effective. These modifications then may restart the cycle of legal challenges to the new laws.

Our compliance with existing and proposed environmental laws is further complicated by the scope of our operations. We operate generation facilities in four different states. EPA and state environmental agencies often implement environmental laws and regulations in a manner designed to meet compliance targets within a particular state. As a result, existing and future environmental laws may cause us to undertake relatively higher cost measures to comply with laws in one state jurisdiction than those that would be applicable or acceptable in another state. The differential in cost between these compliance measures could be substantial, including as a result of substantial additional capital expenditures to install new pollution control facilities or the permanent closure of one or more units of one or more existing coal-fired or gas-fired generation facilities.

The lack of certainty regarding potential future environmental requirements exists even though we must make decisions in the near term to plan for compliance with our assessment of likely future requirements. For example, capital expenditures in pollution control equipment for a given facility to achieve compliance must incorporate our assessment of the impact of all other known or anticipated environmental laws with respect to the operation of the same facility. The resulting costs to comply with all applicable environmental requirements, as they may change from time to time, may have an adverse effect on our results of operations, financial condition and cash flows. For additional information regarding certain environmental regulations to which our business is subject, see "[BUSINESS—Environmental Regulation](#)."

Other Risks

Cybersecurity incidents or failures of our information systems could disrupt our operations, compromise sensitive information, and adversely affect our financial condition and reputation.

We operate in a highly regulated industry requiring the continued operation of advanced information systems, operational technology ("OT"), and network infrastructure. We rely on private and third-party communication infrastructure and computing information systems, and other technology, including hosted servers and internet, to support a variety of business processes and activities. We use information systems to process financial information and operational data for internal reporting purposes and to comply with regulatory financial reporting, legal, tax, and operational requirements. Deliberate or

unintentional cyber incidents could directly or indirectly impact our owned and co-owned generation and transmission assets and OT systems. An incident involving our information technology or OT systems could also impact our ability to complete critical business or operational functions and inhibit our ability to effectively maintain certain financial reporting internal controls. In addition to our OT systems, our business and facilities may be impacted by physical or cyber attacks on the business or facilities of others. Any of these types of events could adversely affect our results of operations, financial performance, or cash flows.

In addition, such incidents could result in unauthorized disclosure of material confidential information, including personally identifiable information or sensitive business information. These events could also impair our ability to raise capital by contributing to financial instability and reduced economic activity. To reduce the likelihood and severity of a cyber incident, we employ procedural and technical controls to help protect and preserve the confidentiality, integrity and availability of data and systems. Despite these protections, a major cyber incident could result in significant business disruptions, compromised or improper disclosure of data, safety risks and significant expense to repair security breaches or replace damaged systems, and could lead to litigation, regulatory action, including penalties or fines, and adverse effects to our results of operations, financial condition and reputation. As cybercriminals become more sophisticated, the cost of proactive defensive measures may increase. We are also subject to mandatory and enforceable North American Electric Reliability Corporation (“NERC”) reliability standards to protect against security risks to the reliable operation of the bulk power system. The consequences of failure to comply with these standards can result in fines and other penalties.

We may be subject to physical attacks, threats, or other interference.

As operators of energy infrastructure, we face a heightened risk of physical attacks, or threats of such attacks, on our electric systems. Our generation and transmission assets and systems are geographically dispersed and are often in rural or sparsely populated areas which make it difficult to adequately detect, defend from, and respond to such attacks and effectively deter and prevent such attacks. Recent physical attacks on us and other electric utilities in the U.S. and the coverage of such attacks by the media may have increased this risk and the risk of copycat attacks. If a significant physical attack occurred, it could disrupt our operations, damage our property, pose health and safety risks, have an adverse impact on our revenues, cause us to incur response costs, and result in other financial losses. It could also cause us to be subject to increased regulation or litigation, and cause damage to our reputation, any of which could have an adverse effect on our business and results of operations.

New technologies and improvements in existing technologies related to the generation, storage and use of electricity may materially change the operation of our business in ways we cannot predict.

Technological developments are affecting many aspects of the business of providing electric services. These developments include the improvement in the efficiency of electricity generation from non-conventional sources, the reduction of energy usage and the development of improved modes of energy storage. In recent years, the technologies for wind and solar-powered generation facilities have become more efficient and less expensive. Continued advances in these technologies may reduce the cost of power generated to a level that is competitive with conventional technologies, such as coal-fired or natural gas-fired generation facilities. In addition, new technologies related to fuel cells and other energy storage could significantly impact the overall demand for electricity, especially when coupled with distributed generation. While we cannot predict the exact nature of how these technological changes will affect our financial results, this trend could adversely affect our members’ demand for electricity, the dispatch of our facilities and, ultimately, our results of operations, financial condition, or cash flows. This adverse effect could be further exacerbated if state or federal governments require (or enhance existing requirements) that a specified percentage of the electricity we sell comes from renewable resources if such renewable technologies are not commercially viable compared to conventional technologies.

Accidents involving Dakota Gas products could cause severe damage to people or property.

As a producer and seller of synthetic natural gas and other byproducts and coproducts of the coal gasification process, including phenol, anhydrous ammonia, ammonium sulfate, carbon dioxide, crude cresylic acid, krypton and xenon gases, liquid nitrogen, naphtha, tar oil, urea and diesel exhaust fluid (“DEF”), Dakota Gas’s operations and the producing and handling of these chemical substances involves significant risks and hazards. Accidents involving chemical substances could result in fires, explosions, pollution or other serious circumstances, which could cause severe damage or injury to persons (employees or otherwise), property or the environment, as well as disrupt our business. Any damage to persons, equipment or property or other disruption to Dakota Gas’s ability to produce or distribute its products could adversely impact our cash flows, results of operations and financial condition and result in significant additional costs to replace or repair our assets.

We could be subject to litigation and recapture of tax credits if carbon oxides we have sequestered are released into the atmosphere.

In February 2024, Dakota Gas concurrently placed into service a geologic sequestration project at the Synfuels Plant and entered into a variety of contractual agreements with an investor to monetize tax credits related to the geologic sequestration of carbon oxides under Section 45Q (“Section 45Q”) of the Internal Revenue Code of 1986, as amended (the “Code”). The tax credits are available for up to twelve years from the time the project reached commercial operation. A variety of factors could result in Dakota Gas not receiving the anticipated benefits of the transaction. A change in the Code or the Internal Revenue Service’s interpretation of tax laws could adversely affect or eliminate the benefit of Section 45Q. As part of the transaction with the investor, Dakota Gas has an obligation to manage the carbon sequestration process and is responsible for the ongoing monitoring of sequestered carbon oxides. We provide a guaranty for Dakota Gas’s payment obligations to the investor. If Dakota Gas or any of its contractors failed to perform their respective obligations, Dakota Gas could be liable to the investor for substantial amounts, including for costs incurred to third parties as a result of the failure. For example, the Internal Revenue Service could disallow claimed tax credits for failure to properly sequester the carbon oxides. Any such failure and any resulting payment obligations on our part could adversely affect our results of operations, financial condition, or cash flows.

Risks Relating to the Exchange Offer and the Bonds

If you do not exchange your Original Bonds in the Exchange Offer, they will continue to be subject to restrictions on transfer and may be difficult to resell.

It may be difficult for you to sell Original Bonds that are not exchanged in the Exchange Offer, because any Original Bonds not exchanged will remain subject to the restrictions on transfer applicable to the Original Bonds. These restrictions on transfer arise because we issued the Original Bonds pursuant to an exemption from the registration requirements of the Securities Act and applicable state securities laws. Generally, Original Bonds that are not exchanged for Exchange Bonds pursuant to the Exchange Offer will remain restricted securities and may not be offered or sold, unless registered under the Securities Act, except pursuant to an exemption from, or in a transaction not subject to, the Securities Act and applicable state securities laws. Other than in connection with this Exchange Offer, we do not intend to register the Original Bonds under the Securities Act.

To the extent any Original Bonds are tendered and accepted in the Exchange Offer, the trading market, if any, for the Original Bonds that remain outstanding after the completion of the Exchange Offer may be significantly more limited. We cannot assure you of the liquidity, or even the continuation, of the trading market for the Original Bonds following the Exchange Offer.

Original Bonds not exchanged in the Exchange Offer will remain outstanding and will mature on their maturity date. The terms and conditions governing the Original Bonds will remain unchanged. For further information regarding the consequences of not tendering your Original Bonds in the Exchange Offer, see the discussions below under the captions [“THE EXCHANGE OFFER—Consequences of Exchanging or](#)

[Failing to Exchange the Original Bonds](#)” and [“CERTAIN U.S. FEDERAL INCOME TAX CONSIDERATIONS.”](#)

You must comply with the procedures of the Exchange Offer in order to receive Exchange Bonds.

Delivery of Exchange Bonds in exchange for Original Bonds tendered and accepted for exchange pursuant to the Exchange Offer will be made only after timely receipt by the Exchange Agent of book-entry transfer of Original Bonds into the Exchange Agent’s account at DTC, as depositary, including an agent’s message (as defined herein), if the tendering holder does not deliver a letter of transmittal and any other required documents. Holders should allow sufficient time to ensure timely delivery of any necessary documents. If the exchange procedures are not strictly complied with, the letter of transmittal or the agent’s message, as the case may be, may be rejected. We are not required to notify you of defects or irregularities in tenders of Original Bonds for exchange. Original Bonds that are not tendered or that are tendered but we do not accept for exchange will, following consummation of the Exchange Offer, continue to be subject to the existing transfer restrictions under the Securities Act and, upon consummation of the Exchange Offer, will no longer have the registration and other rights under the Registration Rights Agreement. See [“THE EXCHANGE OFFER—Procedures for Tendering”](#) and [“THE EXCHANGE OFFER—Consequences of Exchanging or Failing to Exchange the Original Bonds.”](#)

Some holders who exchange their Original Bonds may be deemed to be underwriters, and these holders will be required to comply with the registration and prospectus delivery requirements in connection with any resale transaction. If you exchange your Original Bonds in the Exchange Offer for the purpose of participating in a distribution of the Exchange Bonds, you may be deemed to have received restricted securities and, if so, will be required to comply with the registration and prospectus delivery requirements of the Securities Act in connection with any resale transaction.

An active trading market for the Exchange Bonds may not be sustained.

We have not listed and do not intend to list the Exchange Bonds on any national securities exchange or to arrange for the Exchange Bonds to be quoted on any automated quotation system. Although certain dealers currently make a market in the Original Bonds, and we expect that such market-making activities will extend to the Exchange Bonds, they are not obligated to do so, and may discontinue market-making activities in the Bonds at any time without notice. Accordingly, we cannot assure you that a liquid market for the Exchange Bonds will develop or be maintained. If an active market does not develop or is not maintained, the market price and liquidity of the Exchange Bonds may be adversely affected.

In addition, credit rating agencies periodically review their ratings and ratings methodologies for the companies that they follow, including us, the issuer of the Bonds. A negative change in ratings could have an adverse effect on the liquidity and market price of the Exchange Bonds. A credit rating is not a recommendation to buy, sell or hold securities and may be revised, suspended or withdrawn by the credit rating agency at any time.

USE OF PROCEEDS

The Exchange Offer is intended to satisfy our obligations under the Registration Rights Agreement. See [“THE EXCHANGE OFFER—Registration Rights.”](#) We will not receive any cash proceeds from the issuance of the Exchange Bonds in the Exchange Offer. The Original Bonds surrendered and exchanged for the Exchange Bonds will be retired and canceled. Accordingly, the issuance of the Exchange Bonds will not result in any increase in our outstanding indebtedness.

CAPITALIZATION

The following table sets forth our consolidated capitalization, including our subsidiaries, as of December 31, 2025, on an actual basis without any adjustments to reflect subsequent or anticipated events. You should read the information in this table together with [“USE OF PROCEEDS,”](#) [“MANAGEMENT’S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS”](#) and our consolidated financial statements and the related notes thereto included elsewhere in this prospectus.

	Due Date	Weighted Average Interest Rate at December 31, 2025	December 31, 2025 (in thousands)
First Mortgage Bonds:			
2006 Series	June 2041	6.13%	\$ 200,000
2017 Series	April 2047	4.75%	500,000
2025 Series	Oct. 2055	5.85%	700,000
First Mortgage Obligations:			
2005 Series	Dec. 2028-May 2030	5.85%	90,000
2007 Series	Sep. 2042	5.74%	216,854
2008 Series	Dec. 2028-Dec. 2038	5.98%	413,389
2009 Series	Oct. 2027-April 2040	5.47%	132,222
2011 Series	Oct. 2031-Oct. 2049	4.53%	208,080
2012 Series	Nov. 2044	4.07%	73,949
2015 Series	June 2027-June 2044	4.50%	1,353,420
2016 CoBank Note	April 2046	4.48%	68,333
2016 CFC Note	April 2046	3.74%	51,050
2022 Series	Feb. 2042-Feb. 2062	3.00%	276,810
2024 CoBank Note	Nov. 2034-May 2035	6.14%	200,000
2024 Series	Feb. 2029-Feb. 2054	6.22%	350,525
2007 and 2008 Notes	June 2027-Dec. 2028	5.09%	4,750
2023 Note	Oct. 2043	5.56%	72,000
2025 RUS Loan	June 2033	4.33%	538
Other Bonds and Notes:			
Equipment Notes	Dec. 2035-Mar. 2026	5.09%	21,617
2019 Tax-Exempt Bonds	July 2039	3.63%	150,000
Dakota Coal:			
Equipment notes	Jan. 2026-July 2036	4.91%	66,462
Other		Various	11,806
Total long-term debt			5,161,805

	Due Date	Weighted Average Interest Rate at December 31, 2025	December 31, 2025
			(in thousands)
Less:.....			
Current portion.....			(176,019)
Unamortized debt issue costs.....			(35,447)
Discount payable.....			(1,075)
Total long-term debt, excluding current portion.....			4,949,264
Obligations under finance leases.....			3,532
Total equity.....			1,976,427
Total capitalization.....			<u>\$ 6,929,223</u>

BUSINESS

Overview

We are a not-for-profit G&T cooperative corporation organized under the laws of the State of North Dakota, and are principally engaged in the business of providing wholesale electric services to our members through long-term wholesale power contracts. We were formed in 1961 for the purpose of building and operating large-scale, economical generating plants and high-voltage transmission to meet the power supply requirements of a group of cooperatives above their allocation of hydroelectric preference power from other sources, primarily WAPA. We are the largest G&T cooperative in the United States in terms of land area served by our members. Our G&T members provide wholesale electric service for 138 rural electric and small municipal electric systems to approximately 3.0 million people in nine states: Colorado, Iowa, Minnesota, Montana, Nebraska, New Mexico, North Dakota, South Dakota and Wyoming.

Power Supply

We supply our members' electric power requirements through a portfolio of resources, including generating facilities, long-term purchase contracts and forward, short-term and spot market energy purchases. We own, lease, have undivided percentage interests in, or have power purchase agreements with respect to, various generating facilities. As of December 31, 2025, this portfolio provided us with maximum available power of 9,035 MW, inclusive of both owned generation and purchased power which are identified in the table below.

Type of Fuel	Net Capability (MW) ⁽¹⁾
Coal	2,859
Wind	2,358
Gas	1,854
Market purchases	1,304
Hydroelectric	326
Oil/diesel/jet	175
Solar	114
Recovered energy	45
	9,035

(1) MW based on winter season net generating capacity.

Depending on our system requirements and contractual obligations, we are likely both to purchase and to sell electric power during the same fiscal period. In addition, we use market transactions to optimize our position by routinely purchasing power when the market price is lower than our incremental production cost and routinely selling power to the short-term market when we have excess power available above our firm commitments to both members and non-members. We also use spot market purchases during periods of generation outages at our facilities.

Power Supply Planning

On an annual basis, we and our member systems prepare a Load Forecast ("LF") using econometric forecasting models. The LF process is a coordinated, cooperative process involving us and our members. The econometric models used in the LF are developed for each distribution system and incorporate economic and demographic factors affecting each member's electricity sales. The external data used in the econometric models is obtained from both government and private sector sources such as DOE, Woods and Poole Economics, Food and Agricultural Policy Research Institute, United States Census Bureau, National Oceanic and Atmospheric Administration and Bureau of Economic Analysis. Internal

data used in these models consists of historical energy usage by consumer classification and each member's historic and projected electricity prices. The LF process also incorporates the judgment and knowledge that the distribution systems have of their service territory. In 2026, we finalized the results of a new power requirements study. Our historical peak demand and energy sale volumes reflect that we serve our members' requirements in excess of the capacity and energy provided by WAPA and certain of the members' own generation. As such, our power supply obligation generally increases and decreases at a faster rate than that of the total system. As the proportion of our members' power requirements being served by us continues to increase, our growth rates become closer to those of the total system. Peak demand supplied to members by us grew at an average annual compound rate of 4.9% from 2020 through 2025 and energy requirements supplied by us to members grew at an average annual compound rate of 5.5% from 2020 through 2025. See "[MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS—Key Factors Affecting Results—Changes in Member Load Growth](#)" and "[—Large Load Commercial Program](#)" for forecasts of future growth and potential for growth attributed to large loads.

Power Supply Resources

Twenty years ago, our portfolio of resources was almost exclusively coal generation. However, since then we have significantly diversified our mix of generation resources. Through direct investments and annual payments under renewable power purchase agreements, we have made substantial capital investments and commitments in renewable resources. Wind and solar resources from power purchase agreements—including the most recent agreements signed in 2025 for two wind projects that have not yet come online—will increase the renewable portion of our generating portfolio, which includes waste heat, to more than 2,700 MW when combined with existing wind and solar generation commitments. As of December 31, 2025, coal fired resources represented 31.7% of our overall winter season generation capacity, and natural gas resources represented 20.5%, renewable and green generation represented 27.9% (with a combined total of 2,517 MW of wind, solar, and waste heat generating resources), hydropower purchased from WAPA represented 3.6%, and oil, diesel, jet fuel and other unspecified generation represented the remaining 16.3% of our overall generating capacity. By 2031, coal resources are projected to represent just 27.6% of our overall resource capability, with natural gas resources representing 34.8% and renewable and green resources (wind and solar), together with hydropower, recovered energy, and storage, representing approximately 33.1%, and oil, diesel, and jet fuel along with other purchases from unspecified/undetermined fuel types representing the remaining 4.5%.

Power Purchase Agreements

Our purchased power capacity is becoming increasingly diverse. We have a number of long-term power purchase arrangements of varying capacities for energy generated by various sources with terms scheduled to end ranging from 2026 to 2075. The total amount of capacity we purchased under these contracts as of December 31, 2025, was 4,198 MW, which includes 343 MW of carbon-based generation (coal, natural gas, oil, etc.), 2,551 MW of non-carbon-based resources (hydro, waste heat, and wind) and 1,304 MW of additional power through bilateral purchases of capacity only. As of December 31, 2025, approximately 2,143 MW of our long-term power purchase arrangements are scheduled to expire between 2026 and 2039, with an additional 3,068 MW under longer-term agreements extending beyond 2039.

WAPA Peaking Power

We purchase hydroelectric peaking power from WAPA pursuant to a contract entered into in 1968. This contract provides for us to purchase 268 MW of capacity delivered to our load during peak periods of the winter season (November through the following April) and for us to return to WAPA during off-peak periods an amount of energy equal to the amount of energy that we received. To the extent we have not returned all peaking energy purchased during the winter season to WAPA by the end of the summer season, we must purchase the remaining balance from WAPA. We are obligated to submit to WAPA in writing our estimated winter season peak firm obligation, together with supporting calculations, prior to

each winter season. In 2019 this contract was renewed through 2050 and is separate from any power purchase obligations between WAPA and our members.

Cooperative Structure

A cooperative is a business entity owned by its members, which are also its retail or wholesale customers. Cooperatives are designed to give their members the opportunity to satisfy their collective needs in a particular area of business more effectively than if the members acted independently. As organizations operating on a not-for-profit basis, cooperatives provide services to their members on a cost-effective basis, in part by eliminating the need to produce profits or a return on equity in excess of required margins. Electric cooperatives generally establish rates to recover their cost-of-service and to collect a portion of revenue in excess of expenses, which excess constitutes margins. Margins not distributed to members in cash constitute patronage capital, a cooperative's principal source of equity. Patronage capital is held for the account of the members without interest and returned when the board of the cooperative deems it appropriate to do so. The timing and amount of any actual return of patronage capital to the members depends on the financial goals of the cooperative and restrictions in the cooperative's loan and security agreements.

Our 138 members are classified into four classes (Class A, B, C and D, respectively) depending upon how they are supplied with our electric services:

- Our Class A Members consist of ten wholesale G&T cooperatives, eight distribution cooperatives and one wholesale municipal provider that have entered into long-term wholesale power contracts with us. We supply power directly to and receive revenue directly from our Class A Members. Our operating revenue comes primarily from our Class A Members, and for the years ended December 31, 2025 and 2024, our Class A Members contributed approximately 90.5% and 88.1% of our electric sales revenue, respectively.
- Our Class B Members consist of any municipality or association of municipalities operating within an area served by a Class A Member and which is a member of, and contracts for its electric capacity or energy from, that Class A Member. We currently have one Class B Member. We do not supply power directly to, or receive revenue directly from, our Class B Member.
- Our Class C Members consist of distribution cooperatives and public power districts that are members of our G&T Class A Members. Our Class C Members do not purchase power directly from us, but rather from their respective G&T Class A Members. We currently have 117 Class C Members. We do not supply power directly to, or receive revenue directly from, our Class C Members.
- Our Class D Members consist of electric cooperatives that purchase power directly from us on a basis other than the long-term wholesale power contracts that we have with our Class A Members. We currently have one Class D Member.

Electric cooperatives generally include distribution cooperatives, such as the majority of our Class C Members, and G&T cooperatives, like us and most of our Class A Members. The primary purpose of electric distribution cooperatives is to supply the requirements of their retail consumers through bulk purchases of power and energy and to maintain a distribution system to deliver the electricity necessary to satisfy their consumers' requirements. The primary purpose of a G&T cooperative is to provide wholesale electric power to its member distribution cooperatives.

Wholesale Power Contracts

We have long-term wholesale power contracts for the sale of capacity and energy to our Class A Members. Pursuant to these contracts, we generally sell and deliver to each Class A Member, except Tri-State, all of such member's capacity and associated energy requirements in excess of enumerated amounts of capacity and associated energy available to such member from other specified sources,

primarily WAPA. Our wholesale power contracts with our Class A Members provide that capacity and associated energy are to be furnished in accordance with the member's normal annual load patterns and that our obligations are limited to the extent to which we have capacity, energy and facilities available. All of our wholesale power contracts with our Class A Members extend through 2075, with the exception of our wholesale power contracts with Tri-State, Minnesota Valley, Wright-Hennepin and WMPA, which extend through 2050. In 2025, revenues from electric sales to members with wholesale power contracts expiring in 2050 were approximately 10.1% of our total members sales. After maturity in 2050 or 2075, as applicable, these contracts remain in effect until terminated by either party giving the contractually required notice of its intention to terminate. WAPA's contracts with our members served in the Upper Great Plains ("UGP") region expire in 2050 and contracts with our members served in the Rocky Mountain region ("RMR") expire in 2054. Some of our Class A Members are themselves wholesale cooperatives like us, and, with limited exceptions, the wholesale power contracts they have with their members align with or extend beyond the corresponding expiration dates as our contracts with their respective Class A Member.

Our average wholesale rate in 2025 to Class A Members was \$62.9 per MWh, and total revenue from electric sales to our Class A Members in 2025 was approximately \$2.2 billion, or approximately 90.5% of our total electric sales revenue. In 2025, revenues from electric sales to members with wholesale power contracts expiring in 2050 was approximately 10.1% of our total member sales. The budgeted Class A Member rate for 2026 is \$69.7 per MWh.

Due to the long-term nature of our wholesale power contracts, our Class A membership does not often change but when it does it is most commonly as a result of the admission of new members. Our most recent Class A membership change was the admission of WMPA in 2021.

Neither our wholesale power contracts with our Class A Members nor their wholesale power contracts with our Class C Members provide for a unilateral right of termination of those contracts prior to their end date. Likewise, our bylaws provide that a Class A Member not withdraw from membership until it has met all of its contractual obligations to our cooperative, which would include all obligations under the Class A Member's wholesale power contract with us. Any withdrawal by a Class A Member may only occur upon compliance with such equitable terms and conditions as our Board may prescribe.

Nevertheless, Tri-State has in the past permitted distribution cooperative members to exit from Tri-State under a FERC-approved contract termination payment ("CTP") rate schedule. We are aware of six Tri-State members which have provided notice of future exit from Tri-State, with proposed exit dates ranging from December 2026 to April 2028. Of these six exiting Tri-State members, two are entirely served in the Western Interconnection, where Tri-State buys a fixed amount of power from us. Thus, these member exits located in the Western Interconnection would not directly affect the volume of power and energy we sell to Tri-State. Of the remaining four exiting Tri-State members, two have electric load entirely in the Eastern Interconnection, where Tri-State takes requirements service from us, and two are located in both the Eastern Interconnection and the Western Interconnection. If Tri-State were to permit the exit of a distribution cooperative member located in the Eastern Interconnection taking requirements service from us without first obtaining our consent, we expect that we would seek to enjoin such exit or seek other remedies against Tri-State. See "[LEGAL PROCEEDINGS](#)."

Member Service Area

We provide capacity and energy either directly or indirectly to retail distribution utilities that serve the electric requirements of the farms, ranches, rural homes, businesses and commercial and industrial facilities in our members' service areas, which span 500,000 square miles from the Canadian to the Mexican borders. The service provided by the distribution cooperatives ranges from remote stock-watering facilities on the cattle ranges of Wyoming and Montana to new industrial installations on the outskirts of metropolitan centers in the region.

The majority of the Class A Members have service areas in the agricultural regions in the Dakotas, northwestern Iowa, and southwestern Minnesota. Members 1st Power Cooperative serves a large portion of northeastern Wyoming and southern Montana. East River serves the agricultural regions of eastern South Dakota. Tri-State, located in Colorado, serves distribution cooperatives in Colorado, Wyoming, New Mexico and western Nebraska. The geographic features of the Tri-State service area range from portions of the upper Rockies to the rolling range and farm country of Colorado, New Mexico and western Nebraska. Upper Missouri in Montana and Central Power Electric Cooperative in North Dakota, serve distribution cooperatives located in the oil fields of the upper Missouri River regions of North Dakota and Montana.

Electric Utility Seasonal Variation

Basin Electric's business is subject to seasonal fluctuations in electricity demand. Demand for electricity is generally higher during the summer and winter months due to increased cooling and heating requirements of its members. Seasonal weather patterns may affect system load levels, generation dispatch, and fuel usage.

Territorial Integrity

Distribution cooperatives generally exercise a monopoly in their service areas. South Dakota, Minnesota, Nebraska, Iowa, Wyoming and Colorado assign specific service areas to each distribution cooperative and each public utility within the state. In each of these states, petition must be made to the appropriate state regulatory authorities in order to change these assigned areas. The laws of North Dakota provide that no franchised public utility can expand beyond the city or town in which it has a franchise without a Certificate of Convenience and Necessity from its public utilities commission. In Nebraska, four of the six Class C Members are public power districts, whose boundaries are fixed by organizational law, which can be changed only by a vote of the public. In addition, any change in service territory must be approved by the Nebraska Power Review Board. In South Dakota, loads in excess of 2 MW are biddable to any utility. The various distribution cooperatives do not have territorial conflicts among themselves since assigned boundaries are set forth in their area coverage agreements with each public utility within the state. Our distribution cooperatives have suffered no significant territory losses through local governmental service area annexation.

Deregulation Status

Except for Montana, none of the states that our Class A Members serve have adopted electric restructuring legislation. Montana adopted restructuring legislation in 1997, but electric cooperatives were permitted to opt out of consumer choice provisions of the legislation.

Rate Regulation of Members

Two states in our service territory—Colorado and Wyoming—have statutes regulating electric distribution cooperative associations operating at the state level. In Wyoming, the distribution members of our G&T Class A members are subject to rate regulation by the respective state regulatory authorities. In Colorado, a 1983 law allowed distribution cooperatives the option to opt out of rate regulation by the Colorado Public Utilities Commission through a majority vote of their members before July 1, 1984. All but one of our Class C Members in Colorado chose to opt out. In addition to the state-level regulation, two of our Class A Members — Upper Missouri and Tri-State — are also subject to rate regulation by FERC.

Financial Information

We are a membership corporation, and our members are not subsidiaries. Except for the obligations of the Class A Members under their respective wholesale power contracts with us, we have no legal interest in, or obligation in respect of, any of the assets, liabilities, equity, revenue or margins of such members. In addition, the revenue of the Class A Members is not pledged to us but is received by the respective Class A Member and is the source from which moneys are derived by such Class A Member to

pay for capacity and energy supplied by us under the respective wholesale power contracts as well as from others.

In 2025, two of our Class A Members, Upper Missouri and East River, accounted for 42.7% and 12.8%, respectively, of our total Class A Member revenue. In 2025, sales by Upper Missouri to two of its members, who are also our Class C Members, McKenzie Electric Cooperative, Inc. and Mountrail-Williams Electric Cooperative, represented 19.7% and 15.2%, respectively, of our total Class A Member revenue. Each of our other members accounted for less than 10% of our total Class A Member revenue in 2025.

Rates and Regulation

We provide electric power to our Class A and D Members at rates established by our Board with changes subject to approval by RUS. Our wholesale power contracts with our Class A Members provide that the Board will establish rates to produce revenue sufficient, with our revenues from all other sources, to meet the costs of operation and maintenance (including, without limitation, replacement, insurance, taxes and administrative and general overhead expenses) of the generating plants, transmission system and related facilities, the cost of any power and energy purchased for resale by us, the cost of transmission service, the cost of lease payments, interest expense, and depreciation expense or principal repayments of ours, and to provide for the establishment and maintenance of reasonable financial reserves. Our Board sets our rates to our Class A and D Members at a level intended to achieve and maintain “A” category credit ratings and otherwise to comply with our Indenture covenants and other contractual commitments. Under RUS oversight, rate adjustments approved by our Board are submitted to RUS, which conducts its review consistent with its standard rate-approval practices. We provide all Class A Members between 30 and 45 days’ written notice of any rate schedule change. In addition, we have a number of different incentive rates that we charge to Class A Members, including a non-controlled electric/dual space heat rate and an interruptible rate. We also provide electric power to non-members at contractual rates under long-term arrangements and at market prices in spot sale transactions.

The Federal Power Act contains provisions regulating a “public utility,” as defined in the act, including with respect to the disposition of facilities, the issuance of securities, the assumption of liabilities, and the establishment of rates and charges for the transmission or sale of electricity. The Federal Power Act provides that a public utility does not include an electric cooperative that (1) receives financing pursuant to the RE Act, (2) sells less than 4,000,000 MWh of electricity per year; or (3) is wholly owned by entities that are themselves not public utilities. Beginning in 2019 until July 16, 2025, we were a public utility under the Federal Power Act. On July 16, 2025, we received financing under the RE Act. At the time, proceedings relating to the rates we charged our members for prior periods were pending before FERC. In July 2025, we filed a motion to dismiss these proceedings based on our ceasing to be a public utility for purposes of the Federal Power Act. This motion has been challenged and is still pending before FERC. See [“MANAGEMENT’S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS—Key Factors Affecting Results”](#) and [“LEGAL PROCEEDINGS”](#) for a description of our rate proceedings before FERC involving our members. Our wholesale electric power contracts require our Board to review our rates at least annually and to revise such rates as necessary to produce revenue as described above. Our Indenture requires us to establish and collect rates for the use or the sale of the output, capacity or service of our system that, together with all other revenue, are sufficient to enable us to comply with all of our covenants under the Indenture. See [“MANAGEMENT’S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS—Key Factors Affecting Results—Rate Covenant.”](#) Subject to any necessary regulatory approvals, the Indenture also requires us to establish and collect rates that, together with all other revenue, are reasonably expected to yield an MFI Ratio equal to at least 1.10 for each fiscal year. See [“SUMMARY OF THE INDENTURE—Certain Covenants.”](#)

Transmission

Transmission System Overview

Our transmission system includes facilities on both the Eastern and Western Interconnections which includes over 2,500 miles of high-voltage transmission lines, 115 substations (owned or jointly owned), and 220 telecommunications sites as of December 31, 2025. Our transmission network has expanded through significant capital investments, including facilities that have been developed independently as well as jointly with other transmission owners across the interconnected grid.

We operate and maintain our system to high availability standards. However, like other critical infrastructure operators, we remain exposed to potential physical and cyber threats. Impacts from such events could include operational disruptions, financial losses, lost load or revenue, ransom payments, loss of proprietary information, reputational damage, and increased compliance, legal, and recovery costs.

Key Transmission Projects and System Growth

Over the past six decades, our transmission system has grown in step with major generation development and evolving member needs. The addition of large generating stations, including Leland Olds, Antelope Valley, Laramie River, and Dry Fork, has driven the majority of transmission investments over the years. See [“PROPERTIES—Existing Transmission—Transmission System Overview.”](#)

In recent years, system expansion has been driven by load growth primarily in the Bakken region in North Dakota. New 345-kilovolt and 230-kilovolt facilities have introduced the first extra-high-voltage capability in northwestern North Dakota and strengthened service to growing load centers such as New Town, Williston, Watford City, and the broader Williston Basin. These additions have increased load-serving capacity, improved reliability, and supported continued industrial and population growth.

Significant completed projects in the Bakken include the Antelope Valley Station–Charlie Creek–Neset 345-kilovolt line, placed in service in 2017, and the Roundup–Kummer Ridge 345-kilovolt line, energized in 2024. The Leland Olds–Crane Creek–Tande 345-kilovolt line is currently under construction and on schedule for completion in 2026.

A major new interregional project is being planned as a result of SPP’s Integrated Transmission Plan (“ITP”) process. This project consists of a 345-kilovolt transmission line extending from Laramie River Station in Wyoming through Rapid City, South Dakota, and ultimately terminating at a 345 kV substation near Belfield, North Dakota. This multi-phase project is currently planned for staged tentative in-service dates ranging between 2031 and 2034 that may shift based on equipment lead times and other schedules.

Additional projects identified through SPP’s ITP process include four new lines: Patent Gate–Pioneer 345-kilovolt, Leland Olds–Logan–Crane Creek 345-kilovolt, Dawson County–Judson 230-kilovolt, and the Roundup – Belfield 345-kilovolt. These facilities are expected to further enhance load-serving capability and transfer capacity throughout northwestern North Dakota. Basin Electric is collaborating with WAPA’s Upper Great Plains (“UGP”) division on the development of these projects which are tentatively slated to be placed into service between 2029 and 2035.

In parallel with these regional expansions, we continue to advance a long-standing aging-infrastructure program focused on the systematic replacement of substation components that have reached or exceeded their useful life. This program has been active for eight years and is anticipated to continue for at least the next five to ten years.

Southwest Power Pool Membership and Planning

We have operated within the SPP since October 1, 2015. Membership in SPP has expanded market access and improved opportunities to buy and sell power as system conditions change. With this

integration, our Eastern Interconnection facilities became part of SPP's Open-Access Transmission Tariff ("OATT"), and we actively participate in SPP's regional transmission planning and cost-allocation processes.

SPP's highway/byway cost-allocation methodology continues to shape how new transmission projects are funded. Transmission facilities rated at or above 300 kilovolts are allocated regionally across all SPP members based on load-ratio share, while facilities between 100 and 300 kilovolts are funded one-third regionally and two-thirds within the local transmission zone. Our transmission facilities are located in Zone 19 of SPP's tariff, known as the Upper Missouri Zone. This zone reflects the former Integrated System footprint, which included transmission facilities owned by us, WAPA, and Heartland Consumers Power District.

As a transmission-owning member within SPP, we participate in SPP's planning processes as outlined in the OATT. With the RTO West expansion, we will continue to coordinate closely with both SPP and other Western Interconnection participants to support a smooth transition into the expanded footprint and to help ensure that our transmission system continues to be incorporated into regional planning, operations, and cost-allocation structures in both interconnections.

Transmission Agreements and Coordination

WAPA

Since 1965, when we first interconnected Leland Olds to the WAPA system, we have relied on WAPA to operate our transmission facilities. This arrangement preserves operational efficiency by maintaining a single transmission operator across our shared systems. Today, WAPA continues to provide transmission operator services under several agreements. After joining SPP in 2015, our shared transmission facilities with WAPA became part of SPP's tariff, with SPP assuming functional control and contractual terms were updated accordingly.

Common Use System

The Common Use System ("CUS") is a jointly operated transmission network shared by us, Black Hills Power, and Powder River Energy Corporation ("PRECorp"). The three utilities maintain a joint open-access transmission tariff with FERC that governs transmission service across the combined 230-kilovolt and limited 69-kilovolt facilities located in southwestern South Dakota and northeastern Wyoming. The tariff also includes transmission service associated with the Rapid City DC Tie. Black Hills Power administers the CUS tariff and serves as the transmission operator for our facilities within the CUS footprint.

Regulatory Framework and Open Access Tariffs

Most of our transmission facilities operate under open-access transmission tariffs established through a series of FERC orders that require non-discriminatory access to the nation's transmission grid. FERC's foundational Orders 888 and 890 created the open-access framework, requiring transmission-owning public utilities to provide equal transmission service to all users and promoting competition in wholesale energy markets.

Beginning in the 1990s, FERC increased its role in transmission development and regional planning. While utilities historically planned transmission locally to serve their own customers, FERC's subsequent orders encouraged more coordinated, regional approaches to ensure reliable operation and support expanding wholesale power markets. Through Orders 888, 890, 1000, and 1920, FERC established requirements for integrated transmission planning, interregional coordination, transparency, and cost allocation.

We meet these requirements through active participation through SPP in the Eastern Interconnection and the Colorado Coordinated Planning Group in the Western Interconnection. Order 1000, issued in

2011, requires public utilities to engage in both regional and interregional transmission planning and to allocate costs for new projects based on how those projects benefit the system. Order 1920, issued in 2024, expanded on these requirements by mandating long-term, forward-looking regional planning. Under this order, transmission providers must prepare 20-year regional plans every five years and offer states and interconnection customers opportunities to fund projects that may not otherwise meet traditional planning criteria. We comply with these provisions through our continued involvement in SPP and Colorado Coordinated Planning Group planning processes.

The Missouri Basin Power Project (“MBPP”) is a jointly owned public power project consisting of generation and transmission facilities shared by us, Tri-State, City of Lincoln, Nebraska and Western Minnesota Municipal Power Agency. The four utilities maintain a separate open-access transmission tariff for each of their entitled shares with FERC that governs transmission service across the combined 345-kilovolt and limited 230-kilovolt facilities located in southeast Wyoming, western Nebraska, and northern Colorado. Our ownership of the MBPP transmission facilities on the Western Interconnection is under the Basin Electric’s West Side Transmission System (“BEPW”) tariff. PSCo administers the BEPW tariff and WAPA-RMR serves as the transmission operator for the facilities within the BEPW footprint.

Consistent with FERC’s Standards of Conduct, we have implemented strict separation procedures between protected transmission information and employees engaged in merchant or marketing functions. These procedures are designed to ensure confidentiality, prevent undue preference, and uphold all contractual nondisclosure obligations associated with our transmission operations.

Compliance and Reliability

We maintain a comprehensive compliance program designed to meet all mandatory North American Reliability Corporation (“NERC”) reliability standards that apply to owners, operators, and users of the bulk power system. Because we operate facilities in both the Midwest Reliability Organization (“MRO”) and Western Electricity Coordinating Council (“WECC”) regions, we are registered as a multi-region entity, with MRO serving as our lead regional reliability organization. Both MRO and WECC monitor and enforce our compliance with national and regional reliability standards, and we work closely with each organization to ensure our facilities and operations meet all applicable requirements.

Our internal NERC compliance program covers every aspect of our generation and transmission responsibilities, including system operations, planning, maintenance practices, cybersecurity protections, and physical security of critical assets. Subject matter experts, compliance personnel, and internal audit staff coordinate to review evidence, confirm ongoing compliance, and identify areas requiring updates or mitigation. We also collaborate with our members in areas where transmission and distribution reliability obligations overlap to help ensure the broader system is operated safely and reliably.

We undergo regular monitoring by MRO and WECC, including scheduled compliance audits, unscheduled spot checks, and required self-certifications. In 2022, we completed an MRO-administered audit, and we submitted annual self-certifications in 2023, 2024 and 2025. Through our internal monitoring processes, several potential issues within the Critical Infrastructure Protection (“CIP”) standards were identified and self-reported to MRO. These items are either fully mitigated or in the process of being resolved.

Reliability remains a core operational priority for us, and our continuous monitoring, proactive mitigation efforts, and close coordination with regional reliability organizations help ensure that our facilities support a dependable and resilient bulk power system.

Gasification Operations

Our Gasification operating segment includes Dakota Gas, a wholly owned, for-profit subsidiary that owns and operates the Synfuels Plant, through which it produces and sells synthetic natural gas and other products of the coal gasification process. The Synfuels Plant is a Lurgi process coal gasification plant, which produces synthetic natural gas through the controlled reaction of coal and oxygen in the

presence of steam at elevated temperatures and pressures and is capable of producing 170 MMcf/day if it is solely producing synthetic natural gas. However, with the diversity of products added to the Synfuels Plant, in 2025, SNG production delivered to the pipeline averaged approximately 40 MMcf/day.

We have entered into the Second Restatement of Power Supply Agreement with Dakota Gas pursuant to which it is obligated to purchase and we are obligated to sell electric power and energy for the Synfuels Plant through 2056 at market-based rates. This agreement provides for the purchase by Dakota Gas of all of the power and reserves required for the operation of the Synfuels Plant. In 2025, Dakota Gas purchased 1.1 million MWhs of energy from us.

Gas Transportation Agreements. To transport the synthetic natural gas Dakota Gas sells on the open market, Dakota Gas acquired firm transportation rights on the Northern Border Pipeline Company (“Northern Border”) pipeline system. Dakota Gas currently holds firm transportation rights on the Northern Border pipeline system for 33,481 MMBtu/day and 45,778 MMBtu/day to market hubs located at Ventura and Harper, Iowa, respectively.

Product Diversification. Since its acquisition in 1988, Dakota Gas has improved operating efficiencies and undertaken the manufacture of additional products, including carbon dioxide, anhydrous ammonia, urea, DEF, ammonium sulfate, krypton and xenon crude gas, naphtha, phenol, tar oil, liquid nitrogen and crude cresylic acid. Dakota Gas also constructed compressor facilities and a 168-mile pipeline from the Synfuels Plant to the United States/Canadian border to sell carbon dioxide for use in enhanced oil recovery, and a 6-mile pipeline and six wells to geologically sequester carbon dioxide. These coproduct and byproducts provide Dakota Gas some flexibility to switch the production of products or boiler fuel based on market prices and demand.

Seasonal Variations. Dakota Gas’s fertilizer-related operations are subject to seasonal demand patterns that are influenced by agricultural planting cycles. Demand for nitrogen-based fertilizer products is typically higher in advance of the spring and, to a lesser extent, fall planting seasons, with lower demand during other periods of the year.

Coal and Limestone Operations

Our Coal and Limestone Operations segment includes Dakota Coal, a wholly owned, for-profit subsidiary, incorporated in 1988 in conjunction with the acquisition of the Synfuels Plant to consolidate in Dakota Coal substantially all of the functions relating to the supply of lignite coal to the Synfuels Plant and Antelope Valley Station. Dakota Coal sells coal to us and Dakota Gas at a cost-plus basis that is designed to recover its costs with a reasonable profit. Currently, Dakota Coal’s major business activity relates to supplying lignite coal from the Freedom Mine to the Synfuels Plant, Antelope Valley Station and Leland Olds Station. Lignite production at the Freedom Mine in 2025 was approximately 11.3 million tons, all of which were sold to Dakota Coal.

The Freedom Mine is owned and operated by Coteau. Dakota Coal purchases lignite coal from Coteau on a cost-plus basis pursuant to a lignite sales agreement with Coteau (the “Coteau Lignite Sales Agreement”). Dakota Coal resells that coal to Dakota Gas for use at the Synfuels Plant and to us for use at Antelope Valley Station and Leland Olds Station. The Coteau Lignite Sales Agreement also gives Dakota Coal certain rights related to the development and operations of the Freedom Mine and obligates Dakota Coal to provide financing for the operation of the mine and certain other capital expenditures relating to the Freedom Mine. In addition, Dakota Coal has the right, under other agreements and subject to specific circumstances, to acquire all of the stock of Coteau or specified coal reserves underlying the Freedom Mine. The Coteau Lignite Sales Agreement expires in April 2027, with three remaining successive five-year renewal options.

Pursuant to the Coteau Lignite Sales Agreement, Dakota Coal is required to purchase all of the coal requirements of Antelope Valley Station and the Synfuels Plant from Coteau as well as the coal requirements of Leland Olds Station; provided, that if in our opinion (or that of Dakota Coal) federal, state or local law prohibits or renders uneconomical the use of North Dakota lignite coal at Leland Olds Station,

Dakota Coal may purchase alternative fuels. Dakota Coal purchases coal from Coteau at a price that includes all costs incurred by Coteau for the development and operation of certain dedicated coal reserves used to supply Dakota Coal. Under the Coteau Lignite Sales Agreement, notwithstanding the suspension of lignite coal deliveries due to a force majeure event affecting either or both of Dakota Coal and Coteau, Dakota Coal is nonetheless required to reimburse Coteau for its out-of-pocket expenses and depreciation for such period. Dakota Coal also agrees to provide to Coteau loans or leases necessary to develop, equip and operate the Freedom Mine. All of the equipment financed by Dakota Coal is leased to Coteau and used in the Freedom Mine. In addition, we have provided financial guarantees related to certain reclamation costs for the Freedom Mine. See “[RISK FACTORS](#)” for a discussion of consequences of the acceleration of mine closing costs.

Wyoming Lime owns a limestone processing plant near Frannie, Wyoming. The plant converts limestone to high quality (*i.e.*, high calcium) lime via a high-heat calcining process. This product is sold to us for use in Antelope Valley Station and Laramie River Station for use in stack emission scrubbers and water treatment facilities. It also has other industrial uses and is sold to other customers. The facility is operated by an independent contractor through a marketing and operating agreement.

Dakota Coal acquired Montana Limestone as a wholly owned subsidiary in 2002. Montana Limestone is a limestone quarry contractor that supplies chemical grade limestone to Dakota Coal’s limestone processing plant and to other customers. In addition, limestone is sold to others as a reagent for removing sulfur from combustion gases. Leland Olds Station purchases limestone from Montana Limestone for its scrubbers. Montana Limestone also owns and operates a limestone crushing and processing facility whose customers are primarily agriculture-based.

In 2008, Montana Limestone purchased 50.0% of the shares of The Bighorn Limestone Company (“Bighorn Limestone”). Bighorn Limestone owns surface and limestone reserves in the quarry that Montana Limestone operates. As a result of this acquisition, Montana Limestone has the right, in conjunction with the Western Sugar Cooperative, to long-term control of the limestone reserves.

Environmental Regulation

Our operations are subject to environmental laws and regulations that comprehensively regulate the environmental impacts of our business. Air pollution control regulations require most major sources to obtain permits for construction and operation that impose emissions limitations on electricity generating plants that use fossil fuels. Water protection regulations control the use of water for steam generation and for cooling and require wastewater monitoring and treatment. Our operations generate solid wastes, such as coal combustion residuals, that require management and appropriate treatment or disposal. We may be subject to decommissioning or reclamation requirements upon the cessation of certain activities, like mining, or the closure and removal of facilities. Environmental regulations and specific permit requirements apply to nearly every aspect of our operations. Regulations and permits may require material expenditures to achieve or maintain compliance and can limit our operations. Should we fail to comply with these environmental restrictions, even for reasons beyond our control, we may be subject to significant fines, penalties and operational limitations imposed by regulatory agencies that normally cannot be predicted or estimated. We could also be subject to similar costs and liabilities as a result of non-governmental actions, such as lawsuits brought by environmental groups or private citizens.

In addition, environmental laws impose obligations with respect to releases of hazardous substances, petroleum products and other materials that are part of our facilities or used in our operations. Contamination of sites we own or lease may require us to conduct investigations, removal or other remedial actions, even if we are not at fault for such conditions. While we are not aware of current material obligations for such investigations or cleanups, soil or groundwater contamination may be difficult to detect, and as a result we may be unaware of material liabilities relating to environmental investigation, cleanup, and related claims from federal or state government or private entities.

Environmental laws and regulations are complex and technical, and change frequently, often becoming more stringent over time. Permits required for our operation periodically expire, and such permits may not be subject to renewal on the same or similar terms and conditions. These changes may be induced by legislative, regulatory, and judicial actions regarding environmental standards and requirements that impact our operations and facilities. We may be subject to changes in legal, regulatory, and permitting standards that are excessively expensive to implement and may impair our operations or even require the termination of operations of certain facilities. We cannot predict at this time whether any changes to legislation, regulations or permits will be imposed that will affect us or our subsidiaries' operations, and if such laws, regulations, or permit changes are enacted or imposed, the costs we or our subsidiaries might be required to bear in the future.

From time to time, we or our subsidiaries are alleged to be in violation or in default under orders, statutes, rules, regulations, permits or compliance plans relating to the environment. We may need to respond to notices of violation, enforcement proceedings or challenges to permits, any of which may result in fines or penalties, as well as potentially material compliance costs. In addition, we may be involved in legal proceedings arising under environmental laws in the ordinary course of business.

Air Quality

The Clean Air Act. The Clean Air Act requires the EPA to establish air quality standards that are used to determine emissions limitations imposed upon individual sources of air pollution, such as combustion facilities that generate electricity. The emissions limitations on individual facilities are achieved by pollution control systems, which are implemented through permits issued by the EPA or delegated state agencies for construction or operation of such units. The air quality standards and emissions standards change from time to time, with the result that emissions limitations are typically made more stringent and pollution control requirements become more expensive to implement. Among the provisions of the Clean Air Act that affect our operations are (1) ambient air quality standards that limit the amount of emissions at a certain location or in a certain compliance area, (2) the acid rain program, which requires nationwide reductions of sulfur dioxide (“SO₂”) and nitrogen oxides (“NO_x”) from new and existing fossil fuel-based generating facilities, (3) regulations controlling toxic or hazardous pollutants that may require certain pollution control technologies, (4) requirements to control emissions to reduce regional haze and improve visibility, and (5) New Source Performance Standards (“NSPS”) which set emission standards for new, existing and modified sources. Many of the existing and proposed regulations under the Clean Air Act will impact coal-based generating facilities to a greater extent than other electric generating facilities.

National Ambient Air Quality Standards (“NAAQS”). The national ambient air quality standards (“NAAQS”) are standards set by the EPA Administrator to protect human health and welfare for six pollutants: carbon monoxide, lead, nitrogen dioxide, ozone, particulate matter, and SO₂. EPA periodically revises the NAAQS, setting more stringent air quality standards that areas must attain. States must submit state implementation plans (“SIPs”) detailing how the states will comply with the NAAQS. If a state fails to submit a SIP or EPA disapproves all or part of a SIP, then EPA will issue a federal implementation plan (“FIP”) within two years of finalizing a disapproval or a finding that a state failed to submit a SIP. Our generation resources in Iowa, Montana, Nebraska, North Dakota, South Dakota, and Wyoming are currently all located in areas that are in attainment of all the various NAAQS. However, as discussed below, Iowa has been found to significantly contribute to nonattainment in downwind states and must address interstate transport of emissions in their SIPs and, in the case of Iowa, participate in the Cross State Air Pollution Rule (“CSAPR”) program to reduce interstate transport of emissions. On February 7, 2024, EPA finalized a rule lowering the primary annual PM_{2.5} standard from 12 micrograms per cubic meter (“µg/m³”) to 9 µg/m³. The final rule retained the primary 24-hour and secondary standards for PM_{2.5} as well as the current primary 24-hour and secondary standards for PM₁₀. However, on March 12, 2025, EPA announced that it would reconsider the NAAQS for PM_{2.5}. In addition, on December 27, 2024, EPA issued a final rule to revise the secondary standards for SO₂ to an annual average, averaged over three consecutive years, with a level of 10 parts per billion (“ppb”).

Cross-State Air Pollution Rule (“CSAPR”). In 2011, the EPA promulgated the CSAPR, which required states to adopt programs to reduce power plant emissions that contribute to ozone and fine particle pollution in other states. CSAPR requires a total of 28 states to reduce SO₂ and NO_x emissions to assist in attaining clean air standards. The EPA issued a supplemental rulemaking later in 2011 to require certain states, including Iowa, to reduce summertime NO_x emissions under CSAPR. We own and purchase electricity from facilities in Iowa, a state that is subject to the CSAPR program. Following legal challenges to CSAPR, EPA revised the program in a rule that went into effect in 2017, requiring additional reductions in NO_x emissions from utilities in 22 states in the eastern United States, during the ozone season. In 2019, the D.C. Circuit remanded the rule to the EPA for further consideration. The EPA published a final Revised CSAPR Update Rule in 2021 that placed additional ozone season emission reductions on electric utilities in 12 states. In 2022, the EPA proposed a FIP of the “Ozone Transport Rule” to resolve the agency’s Clean Air Act “good neighbor” obligations for the 2015 ozone NAAQS in “downwind states.” In 2023, the EPA issued its final Good Neighbor Plan with the goal of reducing ozone-forming emissions of nitrogen oxides NO_x from power plants and certain industrial facilities. However, on June 27, 2024, the United States Supreme Court issued a stay and blocked the enforcement of the Good Neighbor Plan based on a preliminary finding that EPA likely failed to adequately respond to comments concerning the plan. On November 6, 2024, EPA published an interim final rule staying the implementation of the Good Neighbor Plan. On January 30, 2026, EPA published a proposed rule which would withdraw EPA’s previous proposed disapproval of the Iowa SIP. If finalized, this rule would resolve outstanding interstate transport obligations for the 2015 ozone NAAQS for Iowa.

Regional Haze. In 2005, the EPA issued the Clean Air Visibility Rule. This new regional haze rule required states to develop plans for imposing emissions reductions upon certain electric generating units by initially requiring them to install best available retrofit technology (“BART”). As a result, the Leland Olds Station installed selective non-catalytic reduction (“SNCR”) on both Units 1 and 2. Low-NO_x burners and separated over-fire air controls to reduce NO_x emissions were installed on Antelope Valley Station Unit 1 and 2. The reductions in both units have resulted in emissions that are below the levels required under the EPA-imposed FIP.

Wyoming developed a SIP that required low-NO_x burners and over-fire air as BART for Laramie River Station. The EPA disapproved of this determination and instead imposed a FIP that also required selective catalytic reduction (“SCR”) technology to control NO_x emissions. We and the EPA negotiated a settlement that was finalized in 2018. The technology package included a SCR on Unit 1 which has been operational since July 1, 2019, and SNCR on Unit 2 and Unit 3 that have been in operation since 2018, with an approximate total cost of \$236 million of which we were responsible for \$97 million.

In 2017, EPA finalized amendments to the regional haze rule that require states to submit SIPs in 2021 to meet the future visibility requirements for the second round of the regional haze rule. The SIPs were to address visibility progress from 2021 to 2028. In December 2024, EPA partially approved and partially disapproved North Dakota and Wyoming SIPs for the Regional Haze second planning period. North Dakota, Wyoming, and industry groups (including us) have filed petitions asking courts to review the disapproval of their SIPs. Both cases are currently held in abeyance at EPA’s request while they review the cases.

Mercury and other Hazardous Air Pollutants. The Clean Air Act also provides for a comprehensive program for the control of hazardous air pollutants (“HAPs”), including mercury. Under this authority, the EPA in 2012 finalized regulations limiting emissions of mercury and other heavy metals from new and existing coal- and oil-fired electric utility steam generating units effective as of April 2015 known as the Mercury and Air Toxics Rule (“MATS rule”). We have installed and are operating controls and monitoring programs to fully comply with the existing requirements of the MATS rule. In 2024 EPA announced final revisions to the MATS rule with more stringent requirements and a compliance date of July 2027. In March 2025 we applied for and were granted a Presidential Exemption for the Antelope Valley Station, the Leland Olds Station, the Laramie River Station and the Dry Fork Station. This exemption pushed out the compliance date for two years to July 2027. In June 2025, EPA announced that it was proposing to repeal certain amendments to the MATS rule. EPA finalized the repeal of this rule on February 24, 2026.

A coalition of environmental groups along with several states have filed a petition for review in the D.C. Circuit Court of Appeals challenging the repeal. We are currently in compliance with the rule as finalized.

Greenhouse Gas Emissions. There has been a push by some federal administrations to regulate GHGs. In April 2024 the Biden Administration finalized GHG regulations for both new and existing electric generating units. States and industry entities filed petitions challenging the rule. In June 2025, the EPA announced a proposed rule that would repeal the April 2024 GHG regulations and all other GHG emission standards for fossil fuel-fired power plants. In addition, the EPA is also proposing to make a finding that GHG emissions from fossil fuel-fired power plants do not contribute significantly to dangerous air pollution. The June 2025 proposed rule also included an alternate proposal that would remove certain restrictions on existing units, but retain the efficiency standards on new natural gas-fired units that were finalized under the Biden Administration. We understand that EPA anticipates finalizing this rule in 2026.

Additional regulatory restrictions on the use of coal or emissions of GHGs are foreseeable, either as a result of current or future legislative or regulatory authority, judicial determinations or international agreements. Our operations, along with those of many other coal-based utilities, could be materially affected by such regulations. The impact to our operations will depend on the development and implementation of applicable regulations and available technologies and cannot be determined at this time.

New Source Review (“NSR”) and Prevention of Significant Deterioration (“PSD”) Program. Under EPA’s NSR program, permits must be obtained to build new sources of air emissions or to make major modifications to existing sources of air emissions to ensure that the area attains and remain in compliance with the NAAQS. Power plants are subject to information collection requests pursuant to EPA’s authority under Clean Air Act Section 114 to assess whether a plant failed to obtain a new PSD or NSR permit prior to making major modifications to the plant, or if the plant was performing routine maintenance and replacement. These Section 114 information requests can be the basis of federal and state enforcement actions, or citizen suits if environmental groups or private entities obtain information through Freedom of Information Act requests. A government enforcement action or adverse legal finding that one of our generators failed to obtain an NSR or PSD permit could result in significant costs in additional pollution controls, operational limitations, penalties, and even early retirement of the plant.

Acid Rain Program. The acid rain program established in 1990 imposed nationwide reductions of SO₂ and NO_x emissions. NO_x emission reductions were achieved by imposing NO_x emissions limitations and pollution control requirements in permits issued for construction or operation of certain fossil-fuel combustion units, including our generation facilities. SO₂ emissions are controlled by the establishment of a nationwide aggregate limitation that is allocated among certain existing generation facilities by the use of tradable emission allowances. SO₂ allowances are allocated for free to some units that were operating in 1990, including several of our combustion units, based on historical or calculated levels of operation and emissions, and give the holder authority to emit one ton of SO₂ during a calendar year for each allowance held. Emission allowances are transferable and can be bought, sold or banked for use in future years following their issuance. We receive annual allowance allocations or otherwise hold sufficient SO₂ allowances for our foreseeable compliance requirements under the acid rain program. Should this situation change, we would need to purchase SO₂ allowances in the allowance markets, like other generators that are allocated insufficient allowances. In recent years, the allowance prices have been low enough that they are not expected to result in material costs. Should market or regulations governing the program change, such costs could be material.

Water Quality

The Clean Water Act. The Federal Water Pollution Control Act as amended (the “Clean Water Act”) regulates the discharge of wastewater and storm water under the National Pollutant Discharge Elimination System permit program. The water quality regulations require us to comply with each state’s water quality standards, including sampling and monitoring of the waters around affected plants. As with

other regulatory programs, changes to the laws and regulations, or changes to our permits, could affect our operations and require additional investment or operating costs.

Cooling Water Intake. Section 316(b) of the Clean Water Act requires the EPA to ensure that the location, design, construction and capacity of cooling water intake structures reflect the best technology available to protect aquatic organisms from being killed or injured by impingement or entrainment. In 2014, the EPA published final regulations establishing standards for cooling water intake structures at existing large generating facilities. The rule provided several compliance alternatives for existing plants such as using existing technologies, adding fish protection systems or using restoration measures. The permit associated with this rule requires the Leland Olds Station monitor and inspect the water intake structure. Both the Laramie River Station and the Antelope Valley Station are subject to the 316(b) rule and have developed the required reporting requirements. Both facilities have closed cooling systems installed and their existing technologies and operational features are considered “Best Technology Available” by the State of Wyoming and the State of North Dakota, respectively.

Effluent Limitations Guidelines (“ELG”). The revised Steam Electric Power Generating ELG rule was finalized in 2021, affecting the Leland Olds Station. All of our other plants are zero liquid discharge facilities and thus are not impacted by the ELG rule. The rule requires zero discharge for bottom ash transport water (“BATW”). In 2024, EPA issued a final rule that established a zero discharge of pollutants limitation for three wastewaters generated at coal-fired power plants: flue gas desulfurization (“FGD”) wastewater, BATW, and combustion residual leachate (“CRL”). The regulation also establishes numeric discharge limitations for mercury and arsenic for CRL that is discharged through groundwater and for a fourth waste stream, called legacy wastewater, that is discharged from certain surface impoundments. In March 2025, EPA announced that it would reconsider the ELGs for steam electric generating units.

Leland Olds Station has a submerged flight conveyer ash handling system. BATW is recirculated/ recycled and not discharged per the ELG rule. Low volume wastewater and coal pile runoff are still discharged in accordance with the state-issued permit. All of our plants are in compliance with the ELG rule but we cannot predict how any future regulations may impact our operations or our ability to comply with such new regulations.

Coal Combustion Residuals (“CCR”). The CCR Rule enacted in 2015 mandated closure of unlined surface impoundments upon a specified triggering event. If after multiple levels of monitoring and an alternate source demonstration, a statistically significant level of contamination could not be attributed to another source, a company was statutorily required to take actions such as retrofit or close a surface impoundment.

In 2019, EPA published proposed amendments to the CCR Rule that included new deadlines to cease waste receipt and initiate closure or retrofit for unlined surface impoundments. The proposed amendments indicated all five Laramie River Station ponds would be required to cease accepting waste in 2020. In 2020, EPA released a final rule (Part A Rule), which established April 11, 2021 as the cease waste receipt deadline for unlined surface impoundments. Basin Electric has retrofitted the surface impoundments and is operating them in accordance with the CCR Rule.

In 2024, EPA finalized changes to the CCR rules to regulate inactive surface impoundments at inactive electric utilities, referred to as “legacy CCR surface impoundments.” Largely unexpected by the regulated community was that the changes to the regulation also covers areas referred to as “CCR management units,” that consist of CCR surface impoundments and landfills that were closed prior to the effective date of the 2015 CCR Rule, and inactive CCR landfills, which include inactive CCR piles and potential beneficial uses at a facility. In this final rule, EPA established identification, groundwater monitoring, corrective action, closure, and post closure care requirements for these areas. CCR management units (“CCRMUs”) are subject to the regulations when they are located at active facilities and inactive facilities with a legacy CCR surface impoundment. We are actively evaluating our compliance and reporting obligations for the William J Neal site where we have posted extension notices to a public website. We have begun evaluating Leland Olds Station, Antelope Valley Station, Dry Fork

Station and Laramie River Station sites for CCRMUs and compliance obligations with this rule. EPA, on March 12, 2025, announced it is reviewing this rule and evaluating whether to grant short- and long-term relief such as extending compliance deadlines. EPA finalized short-term relief in an extension to the rule deadlines by one additional year, which will then allow EPA to make changes to the 2024 rule in 2026. In February 2026, EPA again extended the deadlines by an additional year.

Other Environmental Matters

Renewable Portfolio Standards. We operate in several states that have adopted renewable power standards (“RPS”). RPS generally require certain suppliers of electricity to supply a certain proportion of their electricity from renewable sources. Currently, we comply with or are not subject to RPS in all states in which we operate. Following is a state-by-state summary of RPS that could affect our operations.

Iowa. Iowa does not have an RPS applicable to Basin Electric.

Montana. Montana’s renewable portfolio standard was repealed in 2021 and replaced with an energy development and demonstration grant program. Renewable resources commencing operation after January 1, 2005 and producing energy from the following energy sources are eligible for grants under this program: geothermal electric, solar thermal electric, solar photovoltaics, wind, biomass, hydroelectric, landfill gas, anaerobic digestion, batteries and hydrogen using renewables in fuel cells and batteries.

North Dakota. North Dakota does not have a renewable portfolio standard.

South Dakota. South Dakota does not have a renewable portfolio standard.

Wyoming. Wyoming does not have a renewable portfolio standard.

Hazardous Substances and Waste Handling

The Comprehensive Environmental Response, Compensation and Liability Act. The Comprehensive Environmental Response, Compensation and Liability Act of 1980, as amended (also known as Superfund) (“CERCLA”), requires cleanup of sites at or from which there has been a release or threatened release of hazardous substances. This liability is imposed upon owners or operators of contaminated sites, and upon any person sending waste materials that include hazardous substances to off-site disposal locations. These persons are strictly liable, without fault, and can be held fully accountable for any contaminated site for which they have partial liability. As a result, we could be held responsible for any on-site contamination at our facilities and off-site contamination arising from our operations. CERCLA authorizes the EPA to take any necessary response action to investigate and clean up such sites, and to order responsible parties to take or pay for such actions. To our knowledge, we are not subject to material liability for any contamination under CERCLA. However, our operations involve hazardous substances, pollutants and contaminants, including generating wastes that include hazardous substances, and we send certain amounts of our wastes to third party waste disposal sites. As a result, there can be no assurance that we will not incur liability under CERCLA and similar laws and regulations in the future.

Per- and polyfluoroalkyl substances (“PFAS”). In recent years, federal and state authorities have increased their focus on the impacts of a class of synthetic compounds known collectively as PFAS in both waste and water contexts. We are aware of historic releases of aqueous film-forming foam (“AFFF”) containing PFAS at the Synfuels Plant. AFFF was formerly used by Dakota Gas in firefighting and training activities. We are not aware of any claims relating to AFFF or other PFAS at our facilities or those of our subsidiaries. We have been working with the North Dakota Department of Environmental Quality (“NDDEQ”) on a voluntary investigation of these releases. To date, NDDEQ has not made any claims relating to PFAS at the site of the Synfuels Plant.

Species Protection. Various federal and state laws apply to our operations that protect species, including from unauthorized harm, or “taking.” Examples of such laws include the Migratory Bird Treaty

Act, which prohibits taking of migratory bird species. The Endangered Species Act protects species that are identified and listed by the United States Fish and Wildlife Service as “endangered” or “threatened” as well as critical habitat for such species. The Bald and Golden Eagle Act prohibits taking of eagles. Analogous state statutes exist in several states.

These statutes apply to development and construction activities, limiting the times during the year when construction can occur, and limiting the locations and type of construction that may be authorized. They also apply to operating assets, such as wind energy facilities, which can cause death or injury to birds and bats, some of which are protected species under these statutes. Occasionally, our wind energy facilities’ operations are curtailed due to the presence of protected species. We have developed and implemented avian and bat protection plans for both transmission and wind energy facilities.

New species may be added to the protected species lists from time to time. In addition, conditions may change that result in protected species appearing in or around our operations at unexpected times or places. There can be no assurance that our present or planned operations will not be found to cause or potentially cause taking of a protected species or that circumstances will not change, in which case we may have to modify our operations or, if an unintended taking occurs, incur fines or penalties as a result of violations of species protection statutes.

Mine Reclamation and Closing. Under certain federal and state regulations, owners and operators of coal mines are required to reclaim land disturbed as a result of mining. Owners and operators are required to post financial assurance to ensure a source of funding for such reclamation, to be used by agencies for mine closure and reclamation if the owner or operator fails to complete it.

Payments for mine closing costs for the Freedom Mine will be made to Coteau when Coteau actually incurs costs to complete reclamation after mining is completed in a specific mine area. The estimated mine closing and reclamation costs for the Freedom Mine are approximately \$440.8 million, which are being proportionately charged in coal we purchase from Dakota Coal. Dakota Coal has established a fund for mine closing costs. As of December 31, 2025, the balance in the fund was \$123.7 million.

In addition, we have provided guarantees of certain reclamation obligations of Coteau aggregating approximately \$215 million as of December 31, 2025. As of December 31, 2025, we and Dakota Coal advanced funds to Coteau for the posting of \$21.5 million of surety bonds to support reclamation obligations.

As of December 31, 2025, we have also provided approximately \$31.9 million in guarantees of certain reclamation obligations for Dry Fork Mine.

Duane Arnold Energy Center Closing and Removal. As the owner of an undivided interest in the Duane Arnold Energy Center, an idled nuclear power plant in Iowa with a single unit boiling water nuclear reactor, Corn Belt is responsible for 10% of the costs and expenses related to the decommissioning of the facility. Prior to becoming a Class A Member, Corn Belt established a decommissioning fund, which was fully funded upon becoming a Class A Member, to cover its share of the decommissioning costs associated with the closing and removal of the plant. Our current expectation is the decommissioning fund will be adequate to cover these costs. However, if the amounts funded by Corn Belt are insufficient to cover the costs related to decommissioning the plant, we would be liable for any excess costs. We are aware that NextEra Energy Duane Arnold, LLC (“NEDA”) is exploring a repower of the Duane Arnold Energy Center and Corn Belt is actively working on an asset sale of its ownership interest in the Duane Arnold Energy Center to NEDA. This sale would relieve Basin Electric and Corn Belt of any ongoing responsibilities related to the plant. The Nuclear Regulatory Commission has recently approved the Duane Arnold Energy Center license transfer request filed by NEDA and concluded that NEDA has sufficient funding for the decommissioning of the facility without requiring Corn Belt’s decommissioning funds.

Cyber and Physical Security

Cyber and physical security risks continue to grow for electric utilities that own and operate critical infrastructure. Basin Electric, like others in the industry, is targeted by a range of threat actors, including nation-states and state-sponsored groups, international and domestic violent extremists, and other malicious actors. A successful cyber or physical attack on our facilities could disrupt operations; cause operational or financial losses; reduce revenue; compromise information; damage reputation; require significant resources to respond, mitigate, and recover; and result in liability, litigation, compliance obligations, or system improvement costs.

Basin Electric experienced a limited grid-impacting physical attack in 2023 that resulted in approximately 6.5 hours of impact. We mitigated the effects of this event through our implementation of North American Transmission Forum grid-resilience principles. We incorporate design-based threat assessments and a holistic security posture designed to help prevent, deter, detect, and respond to potential attacks.

As an owner and operator of bulk electric system (“BES”) assets, Basin Electric is subject to mandatory cyber and physical security requirements under the authority of the FERC through Section 215 of the Federal Power Act. The NERC, designated by FERC as the nation’s Electric Reliability Organization, establishes CIP cybersecurity reliability standards. Basin Electric complies with all applicable security-related requirements, monitors its compliance, and reports identified issues to its regional entity. Internal and external audits have in the past identified minor issues that posed little risk to the bulk electric system, and; all were addressed without penalties.

In addition to NERC CIP requirements, Basin Electric incorporates the SANS Five ICS Cybersecurity Critical Controls and employs a defense-in-depth strategy. We also maintain situational awareness and coordinate with industry partners; vendors; and federal, state, and local government entities. Basin Electric regularly participates in industry exercises, including GridEx, the biennial North American electricity-sector security exercise.

Price Transparency and Market Manipulation

Energy Policy Act of 2005 (“EPAAct 2005”) amended the Federal Power Act to promote price transparency in wholesale energy markets. The amended Federal Power Act authorizes FERC to require all market participants, other than those with a de minimis market presence, to disseminate information concerning the availability and price of generation and transmission resources. To date, FERC has focused on requiring greater transparency in the calculation of how much transmission capacity is available, including how much transmission capacity is used to meet local requirements, as well as the submission of quarterly reports on wholesale power sales and transmission transactions.

EPAAct 2005 also amended the Federal Power Act to prohibit manipulation of the energy markets. Section 222 of the Federal Power Act, as implemented through FERC’s regulations, generally prohibits false statements, omissions of material facts and fraudulent or deceitful actions in connection with transactions that are subject to FERC’s jurisdiction, that is, wholesale sales and transmission of electric energy in interstate commerce by regulated utilities and other jurisdictional entities. Section 222 applies to us to the extent that we engage in activities or transactions that are subject to FERC’s jurisdiction. The knowing and willful submission of false information to FERC may be penalized as fraud.

Enforcement

EPAAct 2005 expanded the scope of FERC enforcement and civil penalty authorities for violations of the Federal Power Act. FERC may take specific steps to enforce the Federal Power Act, including FERC’s regulations, rules and orders promulgated thereunder, and may impose civil penalties of up to \$1 million per day, as adjusted for inflation, per violation. FERC may seek enforcement in the federal courts, refer matters to the United States Department of Justice for criminal prosecution, order

disgorgement of profits, revoke authorization to sell energy at market-based rates, and impose civil penalties. As a market participant, we are subject to FERC's enforcement authority.

Competition

The electric utility industry has experienced increasing wholesale competition, enabled by deregulation and revisions to existing regulatory policies, competing energy suppliers, new technology, and other factors. The Energy Policy Act of 1992 amended the Federal Power Act to allow for increased competition among wholesale electricity suppliers and increased access to transmission services by such suppliers. Federal legislation could mandate retail choice in every state, but the prospect of such legislation has diminished due to a variety of factors, including the risks associated with retail competition, the state of the economy, and commodity prices.

A number of other significant factors have affected electric utility operations, including the availability and cost of fuel for electric energy generation, the use of alternative fuel sources for space and water heating and household appliances, fluctuating rates of load growth, compliance with environmental and other governmental regulations, licensing and other factors affecting the construction, operation and cost of new and existing facilities, and the effects of conservation, energy management, and other governmental regulations on electric energy use. All of these factors present an increasing challenge to companies in the electric utility industry, including our members and us, to reduce costs, increase efficiency and innovation, and improve resource management.

We may face competition as a result of the factors described above, including competition from other utilities, fuel sources or as a result of technological innovations. Technological innovations may include methods or products that allow consumers to bypass the electric supplier, to switch fuels or to reduce consumption. These innovations may include, but are not limited to, demand response, distributed generation, solar, energy storage and microgrids. Competition from other utilities may consist of competition from other electric companies or annexations by municipalities. We seek to minimize the risk of competition through price stability, long-term service arrangements, fixed-cost generation and transmission, cost-based coal supplies, and economic diversity among customers. In addition, we serve our members in rural territories that are less attractive to competitors.

Human Capital Resources

Basin Electric relies on a skilled and experienced workforce to support the safe, reliable operation of its generation, transmission, and related facilities. As of December 31, 2025, we and our subsidiaries employed approximately 1,930 employees located in North Dakota, South Dakota, Montana, Nebraska, Wyoming, Arizona and Louisiana. Management focuses on employee safety and health, and maintaining a strong safety culture supported by training programs, safety committees, and emergency preparedness initiatives. We also emphasize workforce development through training and professional growth opportunities designed to support operational excellence, regulatory compliance, and long-term reliability. Employee retention and the promotion of a supportive work environment are important considerations in managing our human capital resources.

PROPERTIES

Generating Facilities

We own, lease, or have undivided percentage interests in various generating facilities which are identified in the table below. For these facilities, the ownership or leasehold share shown represents our portion of total net capability as of December 31, 2025. All of our interests in these facilities or agreements, as applicable, are subject to the lien of our Indenture.

Name	State	Type of Fuel	Net Capability ⁽¹⁾ (MW)	Ownership or Leasehold Share ⁽¹⁾ (MW)	Commercial Operation Date
Coal					
Antelope Valley Station Unit 1	ND	coal	450	450	1984
Antelope Valley Station Unit 2	ND	coal	450	450	1985
Laramie River Station Unit 1 ⁽²⁾	WY	coal	560	92	1980
Laramie River Station Unit 2 ⁽²⁾	WY	coal	570	314	1981
Laramie River Station Unit 3 ⁽²⁾	WY	coal	570	314	1982
Leland Olds Station Unit 1	ND	coal	220	220	1966
Leland Olds Station Unit 2	ND	coal	440	440	1975
Dry Fork Station	WY	coal	405	405	2011
Natural Gas					
Deer Creek Station	SD	gas	297	297	2012
Groton Unit 1	SD	gas	95	95	2006
Groton Unit 2	SD	gas	93	93	2008
Earl F. Wisdom Unit 2 ⁽³⁾	IA	gas/oil	80	40	2004
Culbertson Unit 1	MT	gas	95	95	2010
Lonesome Creek Station Unit 1	ND	gas	45	45	2013
Lonesome Creek Station Unit 2	ND	gas	45	45	2015
Lonesome Creek Station Unit 3	ND	gas	45	45	2015
Lonesome Creek Station Unit 4	ND	gas	45	45	2017
Lonesome Creek Station Unit 5	ND	gas	45	45	2017
Lonesome Creek Station Unit 6	ND	gas	45	45	2021
Pioneer Generation Station Unit 1	ND	gas	45	45	2013
Pioneer Generation Station Unit 2	ND	gas	45	45	2014
Pioneer Generation Station Unit 3	ND	gas	45	45	2014
Pioneer Generation Station Unit 4	ND	gas	225	225	2025
Pioneer Generation Station Unit 5	ND	gas	225	225	2025
Pioneer Generation Station Units 11-22	ND	gas	107	107	2017
Pioneer Generation Station Units 31-36	ND	gas	112	112	2025
8 Wyoming Combustion Turbine Units	WY	gas	48	48	2002
Oil					
Spirit Mound Station Unit 1	SD	oil	60	60	1978
Spirit Mound Station Unit 2	SD	oil	60	60	1978

Name	State	Type of Fuel	Net Capability ⁽¹⁾ (MW)	Ownership or Leasehold Share ⁽¹⁾ (MW)	Commercial Operation Date
Wind Turbines					
188 Wind Turbines	SD/ND	wind	292	292	2009, 2011
Total			5,859	4,839	

Amounts may not sum due to rounding.

- (1) MW reported based on most recent capability test. For wind turbines, MW reported represents the aggregate nameplate rating of the wind turbine units, which provide intermittent capacity.
- (2) Laramie River Station is operated by Basin Electric.
- (3) Earl F. Wisdom Unit 2 is operated by Corn Belt.

Existing Generation Resources

Antelope Valley Station

Antelope Valley Station is a 900 MW two-unit lignite coal-based steam-electric generating station located in Mercer County, North Dakota. Antelope Valley Station Unit 1 went into commercial operation in 1984 and Antelope Valley Station Unit 2 went into commercial operation in 1985. We own a 100% interest in Unit 1 and a 24.2% interest in Unit 2. The remaining 75.8% of Unit 2 at Antelope Valley Station is leased through 2030.

Antelope Valley Station and the Synfuels Plant are surrounded by an area with more than sufficient tons of recoverable lignite coal reserves to supply both facilities, as well as Leland Olds Station, with all of their coal requirements for their respective useful lives. The Freedom Mine, a surface mine owned and operated by Coteau, is located near Antelope Valley Station and the Synfuels Plant. Currently, all lignite coal extracted from the Freedom Mine is sold to Dakota Coal pursuant to the Coteau Lignite Sales Agreement. See "[BUSINESS—Coal and Limestone Operations](#)" for more information on the Coteau Lignite Sales Agreement.

Laramie River Station

Laramie River Station is a 1,700 MW, three-unit coal-based steam-electric generating station located in Platte County, Wyoming. Units 1, 2 and 3 of Laramie River Station were placed in commercial operation in 1980, 1981 and 1982, respectively. We own an approximate 42.3% undivided interest in Laramie River Station.

Laramie River Station is a component of MBPP, which includes Laramie River Station, the Grayrocks Dam and Reservoir (discussed below), certain transmission and transformation facilities and rights under a 60-year transmission service contract with the Nebraska Public Power District. Other participants in MBPP include the City of Lincoln, Nebraska, operating the Lincoln Electric System, Western Minnesota Municipal Power Agency, and Tri-State. The MBPP participation agreement (i) names us as project manager and operating agent, (ii) provides remedies for the failure of any participant to pay its share of costs, (iii) provides for participant input in certain aspects of facility management, (iv) contains restrictions on the transfer of a participant's interest and (v) governs other aspects of participation in Laramie River Station.

Fuel for Laramie River Station is supplied pursuant to a coal purchase contract between us, as project manager, and Western Fuels Association ("Western Fuels"), through the remaining useful life of Laramie River Station (the "Coal Purchase Contract"). Western Fuels is a non-profit Wyoming corporation founded by us and Tri-State for the purpose of acquiring and developing economical fuel resources for Western Fuels' members, consisting of electric cooperative associations and municipal electric systems, as well as for other not-for-profit utilities. Under the Coal Purchase Contract, we are obligated to purchase all of the coal requirements of Laramie River Station from Western Fuels and Western Fuels is obligated to supply us coal through purchases from other companies, which are approved by us, and from the Dry

Fork Mine, a mine in the Wyoming Powder River Basin owned and operated by an affiliate of Western Fuels. The Coal Purchase Contract obligates us to purchase coal at a price that is periodically set by Western Fuels based on all of its costs in connection with producing or acquiring and delivering coal from other companies.

In addition, pursuant to the Coal Purchase Contract we agree to guarantee, as project manager, certain payment obligations incurred by Western Fuels in the performance of its obligations under the Coal Purchase Contract. Further, we, as project manager, are obligated to pay for all of Western Fuels' fixed costs associated with supplying coal to Laramie River Station on a monthly basis regardless of whether such coal is actually delivered to it. Under the terms of the Coal Purchase Contract, Western Fuels is obligated to supply and deliver the total coal requirements of Laramie River Station through the year 2034 unless extended by mutual agreement. We have no reason to believe that Western Fuels will not be able to obtain the coal necessary to satisfy its obligations under the Coal Purchase Contract.

Leland Olds Station

Leland Olds Station is a 660 MW two-unit, lignite coal-fired steam-electric generating station located near Stanton, North Dakota. Unit 1 was placed in commercial operation in 1966 and has a 220 MW capability. Unit 2 was placed in commercial operation in 1975 and has a 440 MW capability. We own 100% of Leland Olds Station.

We have a long-term contract with Dakota Coal for lignite coal used by the facility.

Dry Fork Station

Dry Fork Station is a 405 MW coal-based steam-electric generating station located near Gillette, Wyoming that began commercial operation in 2011. We are the 100% owner of the station.

We have a long-term coal purchase contract with Western Fuels for sub-bituminous coal from the nearby Dry Fork Mine through the life of Dry Fork Station. We are obligated to purchase all of the coal requirements of the Dry Fork Station from Western Fuels and Western Fuels is obligated to supply us coal through purchases from the Dry Fork Mine. The contract obligates us to purchase coal at a price that is periodically set by Western Fuels based on all its costs in connection with producing and delivering coal to the Dry Fork Station.

Deer Creek Station

Deer Creek Station is a 297 MW combined cycle natural gas-fueled plant, with one turbine fueled by natural gas and the second turbine powered by steam generated by the first turbine. Deer Creek Station began commercial operation in 2012 and is an intermediate load facility. The plant is located near Elkton, South Dakota and is 100% owned and operated by us. The plant uses natural gas delivered via the Northern Border Pipeline.

Peaking Resources

We own, lease, or have undivided percentage interests in 1,565 MW of peaking capability as of December 31, 2025, which is included in the table above. These peaking resources are comprised of combustion turbine generating units and natural gas-based reciprocating engines and include both natural gas and oil generation, with commercial operation dates ranging from 1978 to 2025.

Renewable Generation

We own 292 MW of wind resources in North Dakota and South Dakota which is included in the table above, and we have separately added an additional 2,066 MW of wind resources to our portfolio through power purchase agreements, bringing the current total wind generating capacity in our portfolio to over 2,350 MW as of December 31, 2025, with another 235 MW expected to be added in 2026 and 2027. Our

first solar power purchase agreement of 114 MWs came online in 2024. We continue to have discussions with developers for the purchase of additional wind and solar generation.

Corn Belt

We entered into various power purchase agreements with our Class A Member, Corn Belt, that are coterminous with its wholesale power contract with us, pursuant to which we purchase substantially all of Corn Belt’s generation output at its cost while Corn Belt continues to maintain ownership of its generation assets during such period. Corn Belt’s current generation portfolio, which totals approximately 309 MW as of December 31, 2025, is comprised of coal, natural gas, diesel, and wind generating assets, including 87 MW of purchased power resources which we purchase at its cost. Corn Belt is a participant with others in many of the generation assets they own.

Existing Transmission

Transmission System Overview

We provide service to our members located in both the Eastern Interconnection and the Western Interconnection. As of December 31, 2025, we own approximately 2,571 miles of high-voltage transmission lines, have components within or wholly own 115 substations, and own 220 telecommunication sites. Total Basin Electric transmission miles are identified in the table below.

Interconnection	Transmission Tariff	Basin Electric Owned (miles)	Basin Electric Maintained (miles)
Eastern	Southwest Power Pool ⁽¹⁾	2,076	2,146
	Non-tariff facilities	32	57
Western	Common Use System	279	348
	BEPW ⁽²⁾	179	63
	Non-tariff facilities	5	16
Total Basin Electric Miles		2,571	2,630

(1) Basin Electric includes its entitlement share over the MBPP transmission facilities located in the Eastern Interconnection in the SPP transmission tariff.

(2) BEPW represents Basin Electric’s entitlement share over the MBPP transmission facilities located in the Western Interconnection.

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following discussion and analysis of our financial condition and results of our operations should be read together with our consolidated financial statements, including the related notes thereto, included elsewhere in this prospectus. The following discussion contains forward-looking statements based upon current expectations that involve risks and uncertainties. Our actual results may differ materially from those anticipated in these forward-looking statements as a result of various factors, including those set forth under "[RISK FACTORS](#)" and "[FORWARD-LOOKING STATEMENTS](#)" included elsewhere in this prospectus.

Executive Overview

We are a not-for-profit G&T cooperative corporation based in Bismarck, North Dakota, principally engaged in the business of providing wholesale electric services to our members through long-term wholesale power contracts. These electric services generally represent the capacity and energy requirements of our members beyond that available to them from other sources, primarily WAPA, which provides hydroelectric power and transmission services to our members.

We have three operating segments: Electric Utility, Gasification, and Coal and Limestone Operations. The Electric Utility segment provides wholesale electric service and other ancillary services to our members throughout their respective service territories with our own electrical generation and transmission assets and various contractual arrangements. The Gasification segment includes Dakota Gas, which operates a gasification facility that converts lignite coal into synthetic natural gas and other products, including fertilizers, DEF, carbon dioxide, and other oil and chemical products. The Coal and Limestone Operations segment includes Dakota Coal, which purchases coal and coordinates deliveries of coal to the Electric Utility generation facilities and Gasification operations and produces lime and limestone that is used for emissions control at the generation facilities.

In 2025, we sold 39.5 million MWhs of electricity, of which 87% was sold to our Class A Members. Our consolidated net margin and earnings in 2025 was \$116.3 million compared to \$120.8 million in 2024. Our results were primarily impacted by the following factors:

Total operating revenue increased \$272.4 million, or 9.7%.

- Operating revenue at our Electric Utility operating segment increased primarily due to a rate increase on electricity sales to our members effective January 1, 2025, partially offset by a decrease in the recognition of previously deferred non-member revenue.
- Operating revenue at our Gasification operating segment increased mainly due to higher fertilizer, DEF, and synthetic natural gas revenue. Fertilizer and synthetic natural gas sales prices were higher and DEF volumes sold increased largely due to DEF volumes sold on behalf of third parties.
- Operating revenue at our Coal and Limestone Operations operating segment increased largely due to higher lignite coal sales resulting from higher average sales prices.

Total operating expenses increased \$227.6 million, or 8.6%.

- Electric fuel and purchased power and operations and maintenance increased largely due to increased fuel, transmission wheeling, and maintenance expenses. Fuel expenses were higher as a result of higher natural gas prices and higher coal expense. Transmission wheeling rates increased and maintenance expenses were impacted by unplanned work.
- Cost of products sold increased primarily due to third party DEF purchase contracts entered into in 2025, higher prices on natural gas purchases, and higher employee-related costs in lignite coal mining operations.

- Selling, general, and administrative expenses increased largely due to higher freight expenses, absence of insurance recovery proceeds received in 2024, and higher lease expenses.
- These increases were partially offset by decreased Impairment expense due to the absence of impairment expense of \$25.5 million after-tax that was recorded in 2024 related to an investment in NTEC, a generating facility that is not expected to generate cash flows.

Other income decreased \$17.0 million primarily due to lower investment income due to lower interest rates.

Interest and other charges increased \$13.0 million mainly due to an increase in net interest expense primarily due to higher debt balances resulting from additional capital expenditures in electric utility property.

Key Factors Affecting Results

In addition to commodity prices, changes in rates and weather conditions, other factors have been important to our results of operations and financial condition and may significantly impact our outlook in future periods. Some of these factors include the following:

Changes in Member Load Growth

The load we serve through our members continues to grow. Our members' energy requirements that we supplied grew at an average annual compound rate of 5.5% from 2020 through 2025. Over the same period, our members' peak demand increased by an average annual compound rate of approximately 4.9%, reflecting significant growth in system load. This high rate of growth was due in major part to load growth in the Bakken shale formation in western North Dakota and eastern Montana. We currently forecast that our members' energy requirements supplied by us will increase at an average annual compound rate of 3.7% from 2026 through 2031. Over the same period, our members' peak demand is expected to increase by an average annual compound rate of approximately 2.5%, reflecting continued growth in system load. The forecasted growth is exclusive of potential service to large loads as described below. Several factors could impact this forecasted rate of growth, such as market prices for oil and natural gas, developments in the Bakken shale formation, population growth in our service territory, general economic conditions, pipeline permitting and construction, data center construction, technology advancements such as carbon oxide sequestration, and tax advantaged projects.

Major Capital Expenditures

We will continue to have ongoing substantial investments in utility infrastructure. We must invest in adequate generation resources to meet member demand, markets reserve margin requirements, and to back-up the intermittency of renewable energy resources. We also must maintain or expand the transmission facilities we need to reliably serve our members. We currently project \$7.1 billion of capital expenditures for Electric Utility operations for 2026 through 2030. See also "*—Large Load Commercial Program*" below.

Our subsidiaries also expect to incur capital expenditures in coming years. Our Gasification segment is currently projected to spend \$146 million on capital expenditures to fund general projects from 2026 through 2030. See "*—Liquidity and Capital Resources—Projected Capital Expenditures—Gasification*" below for information regarding these projects. As described in "[RISK FACTORS](#)," a change in the strategic direction of Dakota Gas could cause its future capital expenditures to vary significantly from those projected amounts. Our Coal and Limestone Operations segment currently is projected to spend \$262 million on capital expenditures from 2026 through 2030.

We expect that the financing for our projected capital expenditures and the capital expenditures of our subsidiaries principally will come from internally generated funds, advances under our commercial paper program or revolving credit or term loan agreements, RUS loans, loans by us to our subsidiaries, or

issuances of long-term debt securities by us or our subsidiaries. See “[RISK FACTORS](#)” for considerations that could impact the amount and timing of our capital expenditures or cause the financing costs of those expenditures to increase beyond amounts forecasted.

Commodities and Asset Management

We seek to manage the risk that we or our subsidiaries may incur from changes in market prices associated with the inputs, such as fuel, and the outputs, such as electricity, of our assets and those of our subsidiaries. We seek to reduce our exposure to commodity price risk while also obtaining the benefits resulting from more efficient utilization of our assets. Neither we nor our subsidiaries engage in speculative trading. We actively seek to manage exposure to many different commodities, such as natural gas, power, electric transmission capacity, and natural gas pipeline capacity. In addition to these commodities that are commonly managed by energy companies, we also seek to mitigate commodity price risk associated with products of Dakota Gas, such as anhydrous ammonia, tar oil, naphtha, phenol, cresylic acid, urea, and DEF. Our hedging activities include the following markets:

- Power markets, including SPP, MISO, and the bilateral and emerging organized Western Interconnection markets;
- Natural gas markets, including the Upper Midwest, such as Bakken/Williston Basin and Ventura markets; and
- Fuel and agricultural markets.

See “[RISK FACTORS](#)” for a description of limitations on our ability to eliminate or mitigate these risks.

SPP

We have participated in the SPP energy market since 2015. SPP oversees the bulk electric transmission system and wholesale energy market in the central United States on behalf of market participants in fourteen states. Through our participation in SPP, we benefit from, among other things, access to economic purchased power and greater opportunities for economic dispatch of our generation facilities. See “[BUSINESS—Transmission—Southwest Power Pool Membership and Planning](#).”

SPP recently adopted changes to the planning reserve margin requirements that load serving entities must maintain, including seasonal planning reserve requirements. The new winter planning reserve margin requirements effectively increase from 15% to 36% beginning in the 2026-2027 winter season. The summer planning reserve requirement will increase from 15% to 16% beginning in the summer of 2026. Because we are a load serving entity in SPP, we will be required to meet these additional requirements with capacity purchases and/or construction of new facilities. These actions are intended to enable SPP to better prepare for extreme weather conditions and other circumstances that can lead to higher than forecasted demand for electricity. For example, winter storms that stress electrical grids, such as Uri in 2021 and Elliot in 2022, have demonstrated a need for additional winter resources to be available. We cannot predict other potential changes in SPP market rules, planning reserve margins, or other market operations that may occur in the future.

Membership Changes

From time to time, our membership changes. One type of change occurs when a cooperative not previously served by us becomes a new Class A Member. Another type of membership change occurs when we add a Class C Member, which most commonly occurs when one of our Class A Members adds a member. Another change occurs if one of our current members changes its class of membership, or if one of our current Class C Members exits from its Class A Member. Nearly all changes in our membership have resulted in the growth of our requirements. Most Class A Members have wholesale power contracts that extend through 2075, except for four of those contracts that extend only until 2050. We cannot predict whether we will continue to add new members in the future. If we do, our electricity

revenues from sales to members likely would increase and sales to non-members likely would similarly decrease. See [“BUSINESS—Cooperative Structure.”](#)

Rate Structure

Our wholesale power contracts with our Class A Members provide that our Board will establish rates to produce revenue sufficient, together with all of our other revenue, to pay the cost of operation and maintenance of all our generation, transmission system and related facilities, the cost of any power and energy purchased for resale by us, the cost of transmission service, the cost of lease payments, interest expense and depreciation expense or principal repayments of ours, and to provide for the establishment and maintenance of reasonable financial reserves. Our Board sets our rates to our Class A and D Members at a level intended to achieve and maintain “A” category credit ratings and otherwise to comply with our Indenture covenants and other contractual commitments. In addition, we have a number of different incentive rates that we charge to our Class A Members, including a non-controlled electric/dual space heat rate, and an interruptible rate. Our wholesale power contracts with our Class A Members obligate us to review the rates at least annually and to revise such rates as necessary to produce revenue as described above. We also maintain a rate stability fund that is intended to act as a cushion for our membership to help avoid or slow unexpected rate increases. See [“BUSINESS—Rates and Regulation”](#) and [“—RUS Financing”](#) below for a description of how our rates are regulated; see also [“LEGAL PROCEEDINGS”](#) for a description of existing proceedings before FERC relating to our rates and our Class A Members.

The average wholesale rates paid by our Class A Members were \$62.9 per megawatt-hour (“MWh”) in 2025, \$59.1 per MWh in 2024 and \$60.0 per MWh in 2023. Effective January 1, 2026, we implemented a Class A Member rate increase of approximately \$6 per MWh, or approximately 10%. Because we forecast significant future capital expenditures to accommodate load growth (see [“—Liquidity and Capital Resources—Projected Capital Expenditures”](#) below), we expect that additional rate increases will be required to maintain our “A” category credit ratings.

Rate Covenant

The Indenture requires us to establish and collect rates for the use or the sale of the output, capacity or service of our system that, together with all other revenue, are sufficient to enable us to comply with all of our covenants under the Indenture. Subject to any necessary regulatory approvals, the Indenture also requires us to establish and collect rates that, together with all other revenue, are reasonably expected to yield an MFI Ratio for each fiscal year of at least 1.10, which is calculated by dividing the “Margins for Interest” for a period by the “Interest Charges” for such period. The definition of “Margins for Interest” takes into account any item of net margin, loss, gain or expenditure of any affiliate or subsidiary of ours only if we have received such net margins or gains as a dividend or other distribution from such affiliate or subsidiary or if we have made a payment with respect to such losses or expenditures. We were in compliance with the MFI Ratio requirement for each of 2025, 2024 and 2023, respectively. For the definitions of “Margins for Interest” and “Interest Charges,” see [“SUMMARY OF THE INDENTURE—Definitions.”](#)

Net Margin and Patronage Capital

We operate our Electric Utility business on a not-for-profit basis and, accordingly, seek to generate revenue sufficient to recover our cost of service and produce margins sufficient to establish reasonable financial reserves, meet financial coverage requirements and accumulate additional equity as determined by our Board. Revenue in excess of expenses in any year is designated as net margins in our consolidated statements of operations. We designate retained net margins in our consolidated balance sheets as patronage capital, which we assign to each of our patrons, including our Class A and Class D Members, on the basis of its business with us. Any distributions of patronage capital are subject to the discretion of our Board and restrictions contained in the Indenture. See [“SUMMARY OF THE INDENTURE.”](#)

Future of Dakota Gas

The financial performance of our subsidiary, Dakota Gas, has had and is expected to continue to have a significant impact on our financial results. Although Dakota Gas has been profitable in the past, our Gasification segment incurred net losses of \$34.8 million and \$31.3 million for the years ended December 31, 2025 and 2024, respectively. Dakota Gas's financial performance is exposed to significant commodity price volatility and thus can experience operating losses. Negative cash flows could continue at Dakota Gas if commodity prices remain low for an extended time. For these reasons, we continue to evaluate various strategic options, including the sale to potential buyers of the equity or assets of Dakota Gas, in whole or in part, and the potential retirement or repurposing of the Synfuels Plant. Although we previously wrote off the value of the coal gasification assets of the Synfuels Plant, we could incur an additional impairment related to the value of our non-coal gasification assets investments in Dakota Gas, in whole or in part, as a result of any transaction to sell the equity or some or all of the assets of Dakota Gas or decommissioning or repurposing of the Synfuels Plant. See "[RISK FACTORS](#)" for a discussion of additional risks relating to a change in the strategic direction of Dakota Gas.

Tax Status

We are subject to federal and state income taxation, but, as a cooperative, we are allowed to exclude from income patronage margins allocated as patronage capital and we allocate all of our patronage margins to our members to receive such an exclusion. The United States Internal Revenue Service (the "IRS") could challenge whether all of our margins are patronage-related and, if the challenge were successful, we could have additional tax liabilities as a result. Our subsidiaries, except for Basin Cooperative Services, are not organized as cooperatives and are taxed as for-profit corporations. As a result, these subsidiaries cannot reduce their taxable income by making a patronage allocation.

We and our subsidiaries (the "Consolidated Group") file a consolidated income tax return and have entered into tax sharing agreements. Income taxes are allocated among members of the Consolidated Group based on a method under which such taxes approximate the amount that would have been computed on a separate company basis. The tax-sharing agreements obligate members of the Consolidated Group to contribute to the payment of a consolidated U.S. federal income tax liability on the basis stated above. However, under the provisions of the Code currently in effect, the members of the Consolidated Group remain jointly and severally liable for the payment of the entire consolidated income tax liability.

For further information regarding our taxable status, see Note 13 to consolidated financial statements.

Environmental

Our operations are subject to significant environmental regulation. Our coal-fired and natural gas-fired generation facilities constitute stationary sources of emissions that are regulated by the Clean Air Act, the Clean Water Act and other laws and regulations. For more than a decade, the regulation and proposed regulation of air emissions from these sources has vacillated significantly based on the policies of the then-current federal administration and the outcome of litigation and regulatory proceedings accompanying changes or proposed changes in law under the Clean Air Act. Our operations also are subject to the Clean Water Act and other federal and state laws relating to the use and management of hazardous and solid wastes and other environmental matters. Costs to comply with current and future environmental regulations will affect our results of operations, financial condition and cash flows. See "[RISK FACTORS](#)" for a description of ways in which current or future environmental regulation may impact our financial results and "[BUSINESS—Environmental Regulation](#)" for additional information regarding the scope and nature of environmental regulation to which we are subject.

Large Load Commercial Program

Our service territory benefits from a cooler climate, available land suitable for industrial-scale development, and abundant wind and natural gas reserves, which are favorable conditions for the

location of large data centers by hyperscalers. These potential loads provide unique challenges to our cooperative business model through additional generation and transmission requirements, concentration of revenue, and the ongoing reliability of the bulk electric system. To meet the obligation to serve these large loads, insulate our existing membership from rate pressure associated with new generation and transmission requirements, and to protect our financial condition from the risk of stranded assets, our Board adopted a “Large Load Commercial Program” in 2025. Under this program, we seek to meet these new loads’ requirements under a market price passthrough rate structure and require these loads to contribute in some form a substantial portion of the capital required to construct or acquire the assets necessary to serve their loads. See “[RISK FACTORS](#)” for a description of factors impacting our capital expenditures associated with potential service to large loads.

NextEra Energy Resources submitted an application under our Large Load Commercial Program in 2025. NextEra Energy Resources has also signed a memorandum of understanding with Basin Electric and our member cooperatives to explore the possible joint development of a new 1,450-MW combined-cycle natural gas facility to be located in Mercer County, North Dakota. This project is still in early stages of development.

RUS Financing

We have entered into a loan contract (the “RUS Loan Contract”) with the United States of America, acting by and through the Administrator of the RUS, whereunder RUS advanced funds to us on July 16, 2025, pursuant to the Rural Electrification Act of 1936 (the “RE Act”). Under the RUS Loan Contract, we must give RUS 30 days’ notice of any proposed change to our general rate structure. We also are prohibited from amending our wholesale power contracts, including the rate schedule attached to such contracts, without giving RUS 60 days’ notice of the proposed change. If RUS objects to the proposed change, we cannot make it. See “[BUSINESS—Rates and Regulation](#)” for a description of how our rates are regulated.

In January 2025, we signed a commitment letter with RUS to receive grant and loan funding under the New ERA program for a number of existing and proposed renewable projects. The final amount and availability of funding under the program will be subject to meeting program requirements and entering into binding agreements with RUS. Currently, it is unclear whether RUS will proceed to enter into such binding agreements. In addition, we anticipate submitting a construction work plan for new transmission, upgrades to our existing generation and transmission facilities, and certain other eligible capital projects to RUS in the first half of 2026.

Results of Operations

Provided below is a summary and discussion of our operating results on a consolidated basis for the years ended December 31, 2025, 2024 and 2023, followed by a discussion of the operating results of

each of our operating segments for the year ended December 31, 2025 compared to 2024, and for the year ended December 31, 2024, compared to 2023.

Consolidated Summary

The following table summarizes our consolidated net margin and earnings for the years ended December 31, 2025, 2024, and 2023:

(in thousands)	2025	2024	2023	Change (2025 to 2024)	Change (2024 to 2023)
Electric Utility	\$ 104,712	\$ 125,583	\$ 149,968	(16.6)%	(16.3)%
Gasification	(34,751)	(31,300)	(47,722)	11.0 %	(34.4)%
Coal and Limestone Operations....	12,698	(3,658)	(1,414)	(447.1)%	158.7 %
Other (a).....	33,613	30,154	46,684	11.5 %	(35.4)%
Net margin and earnings attributable to Basin Electric	\$ 116,272	\$ 120,779	\$ 147,516	(3.7)%	(18.1)%

(a) Includes intersegment eliminations.

2025 Compared to 2024

- Electric Utility net margin decreased primarily due to higher operating expenses related to increased fuel, transmission wheeling, and maintenance expenses, and a decrease in the recognition of previously deferred non-member revenue partially offset by increased member sales primarily due to higher average rates effective January 1, 2025.
- Gasification net loss increased primarily due to higher operating expenses related to increased cost of products sold and selling, general and administrative expenses, partially offset by higher synthetic natural gas revenue and higher fertilizer revenue.
- Coal and Limestone Operations net earnings increased primarily due to higher average sales prices of lignite coal partially offset by higher operating expenses related to mining operations.

2024 Compared to 2023

- Electric Utility net margin decreased primarily due to lower electricity sales to non-members and higher operating expenses related to increased purchased power and maintenance expenses, partially offset by increased sales to members.
- Gasification net loss decreased primarily due to the monetization of tax credits related to the capture and sequestration of CO₂ partially offset by lower natural gas revenue primarily due to lower prices.
- Coal and Limestone Operations net loss increased primarily due to higher operating expenses related to mining operations and interest expense, partially offset by higher revenue primarily due to higher coal volumes sold.

Electric Utility Results

Our operating revenue from Electric Utility operations is derived from electricity sales to our members and to non-members (including Dakota Gas). Our revenues from our sales to our members are a function of the volume of those sales and our rates, particularly our rate to our Class A Members. See “—Key Factors Affecting Results—Rate Structure” above.

Major factors affecting demand for power from our members include fluctuations of normal seasonal weather patterns, growth or decline in our members’ membership customer base and requirements for power. Wet and dry weather conditions impact our members’ irrigation loads. Expansion of our

distribution members' load is affected by new operations in their service territories and changes in the size, amount and usage of electric operated machinery and equipment. Energy sold to our members increased between 2023 and 2025 as load, particularly in the Bakken region, increased significantly year over year.

Major factors affecting sales to non-members include: (i) the availability of our generating facilities to produce energy in excess of our member requirements and (ii) market prices for electric energy and the cost of the fuel for our generation, particularly natural gas.

(in thousands)	2025	2024	2023	Change (2025 to 2024)	Change (2024 to 2023)
Operating revenue:					
Sales of electricity to members	\$ 2,162,056	\$ 1,995,959	\$ 1,926,214	8.3 %	3.6 %
Sales of electricity to non-members	208,962	208,373	280,761	0.3 %	(25.8)%
Regulatory deferred revenue recognized	18,000	60,000	65,000	(70.0)%	(7.7)%
Other	7,346	6,500	7,563	13.0 %	(14.1)%
Total operating revenue	2,396,364	2,270,832	2,279,538	5.5 %	(0.4)%
Operating expenses:					
Fuel and purchased power	1,116,603	1,074,416	1,077,496	3.9 %	(0.3)%
Operations and maintenance	758,006	679,558	662,056	11.5 %	2.6 %
Depreciation and amortization	216,612	204,903	203,527	5.7 %	0.7 %
Total operating expenses	2,091,221	1,958,877	1,943,079	6.8 %	0.8 %
Operating margin	305,143	311,955	336,459	(2.2)%	(7.3)%
Other income	64,981	77,804	83,548	(16.5)%	(6.9)%
Interest and other charges, net	264,200	273,315	268,735	(3.3)%	1.7 %
Income tax expense (benefit)	1,212	(9,139)	1,304	(113.3)%	(800.8)%
Net margin	\$ 104,712	\$ 125,583	\$ 149,968	(16.6)%	(16.3)%
Electricity energy sales (in thousand MWh):					
Member sales	34,361	33,772	32,082	1.7 %	5.3 %
Non-member sales	5,125	5,061	6,082	1.3 %	(16.8)%
Total electricity energy sales	39,486	38,833	38,164	1.7 %	1.8 %
Peak billing demand (in MW)	5,150	5,134	4,702	0.3 %	9.2 %
Average rate per MWh:					
Member sales	\$ 62.92	\$ 59.10	\$ 60.04	6.5 %	(1.6)%
Non-member sales	\$ 40.77	\$ 41.17	\$ 46.16	(1.0)%	(10.8)%

2025 Compared to 2024

Electric Utility net margin decreased \$20.9 million as a result of:

Operating revenue increased \$125.5 million mainly due to:

- Sales of electricity to members increased \$166.1 million primarily due to higher average member rates effective January 1, 2025 and increased energy sold. Energy sold increased 589,000 MWhs principally due to Class A Member load growth.

This increase was partially offset by the recognition of previously deferred non-member revenue of \$18.0 million in 2025 compared to \$60.0 million of previously deferred revenue recognized in 2024.

Fuel and purchased power increased by \$42.2 million mainly due to increased fuel expense of \$55.2 million due to higher natural gas prices and higher coal expense resulting from higher generation from coal facilities and increased coal prices. Partially offsetting the increase was a decrease in purchased power of \$13.1 million due to lower volumes purchased.

Operations and maintenance increased \$78.4 million mainly due to:

- Transmission wheeling expense increased \$40.8 million largely as result of higher wheeling rates.
- Maintenance expense increased \$28.9 million mainly due to unplanned maintenance work performed at Leland Olds Station.
- Increased production expenses of \$6.8 million primarily due to higher employee-related expenses and increased emissions control products expense as a result of higher electricity generation.

Depreciation and amortization increased \$11.7 million mainly due to new gas generating facilities and investments in transmission placed in service in 2025.

Other income decreased \$12.8 million mainly due to lower interest income primarily due to lower interest rates.

Interest and other charges, net decreased \$9.1 million mainly due to absence of impairment expense of \$25.5 million after-tax that was recorded in 2024 related to an investment in NTEC, a generating facility that is not expected to generate cash flows. Partially offsetting the decrease was an increase in net interest expense primarily due to higher debt balances.

2024 Compared to 2023

Electric Utility net margin decreased \$24.4 million as a result of:

Operating revenue decreased \$8.7 million mainly due to:

- Sales of electricity to non-members (before recognition of previously deferred revenue) decreased by \$72.4 million. The decrease in revenue from non-member sales is primarily attributed to lower volumes sold and lower prices. Energy sold to non-members decreased 1.0 million MWhs and the average sales price decreased \$4.99 per MWh.
- Previously deferred non-member revenue in the amount of \$60.0 million was recognized in 2024 compared to \$65.0 million of previously deferred revenue recognized in 2023.

These decreases were partially offset by an increase in sales of electricity to members of \$69.7 million primarily due to increased energy sold. Energy sold increased 1.7 million MWhs principally due to Class A Member load growth.

Fuel and purchased power decreased by \$3.1 million mainly due to decreased fuel expense of \$34.8 million due to lower natural gas prices and lower coal expense resulting from lower generation from coal facilities. Partially offsetting the decrease was an increase in purchased power of \$31.8 million due to higher volumes purchased partially offset by lower power prices.

Operations and maintenance increased \$17.5 million mainly due to:

- Maintenance expense increased \$5.6 million mainly due to additional planned maintenance work performed.
- Increased production expenses of \$5.5 million primarily due to higher employee-related expenses, contracted services, and property insurance.
- Higher general and administrative expenses of \$5.4 million primarily due to higher employee-related expenses and administrative fees.

Depreciation and amortization was comparable to 2023.

Other income decreased \$5.7 million mainly due to absence of liquidated damages settlement proceeds that were received in 2023 and lower interest income.

Interest and other charges, net increased \$4.6 million mainly due to after-tax impairment expense of \$25.5 million that was recorded related to an investment in NTEC, a generating facility that is not expected to generate cash flows. Partially offsetting the increase were a \$16.4 million reduction in losses on our investment in Dakota Gas and lower net interest expense primarily due to higher capitalized interest.

Gasification Results

Gasification operating revenue is mainly derived from the sale of synthetic natural gas, carbon dioxide, anhydrous ammonia, urea, DEF and various other products produced by Dakota Gas.

(in thousands)	2025	2024	2023	Change (2025 to 2024)	Change (2024 to 2023)
Operating revenue:					
Synthetic natural gas	\$ 106,811	\$ 79,433	\$ 129,028	34.5 %	(38.4)%
Fertilizers and diesel exhaust fluid	318,982	227,749	235,852	40.1 %	(3.4)%
Other byproducts and miscellaneous	68,272	75,221	79,349	(9.2)%	(5.2)%
Total operating revenue	494,065	382,403	444,229	29.2 %	(13.9)%
Cost of products sold					
Cost of products sold	468,697	421,997	415,227	11.1 %	1.6 %
Selling, general and administrative	104,800	39,373	33,525	166.2 %	17.4 %
Depreciation and amortization	41,537	38,532	32,883	7.8 %	17.2 %
Impairment of assets	4,164	4,013	5,035	3.8 %	(20.3)%
Total operating expenses	619,198	503,915	486,670	22.9 %	3.5 %
Operating deficit	(125,133)	(121,512)	(42,441)	3.0 %	186.3 %
Other income					
Other income	122,072	125,968	9,252	(3.1)%	1261.5 %
Interest and other charges, net	34,671	36,967	26,533	(6.2)%	39.3 %
Income tax benefit	(2,981)	(1,211)	(12,000)	146.2 %	(89.9)%
Net loss	\$ (34,751)	\$ (31,300)	\$ (47,722)	11.0 %	(34.4)%
Sales volumes:					
Synthetic natural gas (dekatherms in millions)	33.9	41.0	40.3	(17.3)%	1.7 %
Fertilizer products (tons in thousands)	396.9	425.5	417.8	(6.7)%	1.8 %
Diesel exhaust fluid (gallons in millions)	82.5	59.5	39.0	38.7 %	52.6 %

2025 Compared to 2024

Gasification net loss increased \$3.5 million as a result of:

Operating revenue increased \$111.7 million mainly due to:

- Synthetic natural gas revenue increased by \$27.4 million primarily as a result of higher natural gas prices, partially offset by lower volumes sold. Realized prices of \$3.15 per dekatherm were 62 percent higher.
- Fertilizer and DEF revenue increased \$91.2 million. Fertilizer sales revenue increased \$38.2 million due to higher fertilizer prices, partially offset by a decrease in volumes sold. DEF revenue increased \$53.0 million largely due to DEF volumes sold on behalf of third parties.

Cost of products sold increased by \$46.7 million primarily due to third party DEF purchase contracts entered into during 2025 and higher natural gas purchases due to higher prices.

Selling, general and administrative increased by \$65.4 million largely due to higher freight expenses, absence of insurance recovery proceeds received in 2024, and higher lease expenses. Freight expenses increased by \$31.4 million mainly due to a change in reporting revenue gross versus net due to changes in DEF and fertilizer contracts.

Depreciation and amortization increased by \$3.0 million mainly due to investments in infrastructure enhancement projects to improve the availability of the Synfuels Plant.

Impairment of assets were comparable to 2024.

Other income was \$3.9 million lower largely due to reduced benefits from the monetization of tax credits related to the capture and sequestration of CO₂ through Dakota Gas's investment in Dakota Carbon Services LLC and a loss on the extinguishment of debt of \$0.9 million.

Interest and other charges, net decreased \$2.3 million largely due to lower interest expense related to recognition of tax credit monetization and lower debt balances.

Income tax benefit was higher primarily due to higher losses before income taxes.

2024 Compared to 2023

Gasification net loss decreased \$16.4 million as a result of:

Operating revenue decreased \$61.8 million mainly due to:

- Synthetic natural gas revenue decreased by \$49.6 million as a result of lower natural gas prices. Realized prices of \$1.94 per dekatherm were 41 percent lower.
- Fertilizer and DEF revenue decreased \$8.1 million. Fertilizer sales revenue decreased \$21.8 million due to lower fertilizer prices partially offset by a slight increase in volumes sold. This decrease was partially offset by increased DEF revenue of \$13.7 million due to higher volumes sold partially offset by lower prices.

Cost of products sold increased by \$6.8 million mainly due to higher coal expense and increases in various other operating expenses at Dakota Gas due to increased capacity that resulted from the absence of planned maintenance that occurred in 2023. This increase was partially offset by decreased purchases of natural gas of \$27.2 million mainly due to lower prices.

Selling, general and administrative increased by \$5.9 million largely due to higher insurance expenses and lower insurance recovery proceeds.

Depreciation and amortization increased by \$5.6 million mainly due to investments in CO₂ capture and sequestration assets to monetize tax credits.

Impairment of assets were comparable to 2023.

Other income was \$116.7 million higher largely due to the monetization of tax credits related to the capture and sequestration of CO₂ through Dakota Gas's investment in Dakota Carbon Services LLC.

Interest and other charges, net increased \$10.4 million largely due to interest expense related to recognition of tax credit monetization.

Income tax benefit was lower primarily due to lower losses before income taxes and an increase in the income tax valuation allowance on deferred tax assets.

Coal and Limestone Operations Results

Coal and Limestone Operations revenue is mainly derived from the sale by Dakota Coal of lignite coal for use at our generating facilities and for coal gasification at Dakota Gas. In addition, Dakota Coal operates a limestone quarry and sells lime and limestone to Basin Electric and other third parties.

(in thousands)	2025	2024	2023	Change (2025 to 2024)	Change (2024 to 2023)
Operating revenue	\$ 304,259	\$ 258,904	\$ 243,130	17.5 %	6.5 %
Cost of products sold	235,452	217,038	208,991	8.5 %	3.9 %
Selling, general and administrative	9,810	8,752	5,722	12.1 %	53.0 %
Depreciation, depletion and amortization	18,612	16,042	13,090	16.0 %	22.6 %
Total operating expenses	263,874	241,832	227,803	9.1 %	6.2 %
Operating margin	40,385	17,072	15,327	136.6 %	11.4 %
Other income	16,217	16,467	15,608	(1.5)%	5.5 %
Interest and other charges, net	13,669	11,379	8,157	20.1 %	39.5 %
Income tax expense (benefit)	7,235	2,603	3,109	177.9 %	(16.3)%
Earnings including noncontrolling interest	35,698	19,557	19,669	82.5 %	(0.6)%
Earnings attributable to noncontrolling interest	(23,000)	(23,215)	(21,083)	(0.9)%	10.1 %
Net earnings (loss)	\$ 12,698	\$ (3,658)	\$ (1,414)	(447.1)%	158.7 %
Sales volumes:					
Lignite coal (tons in millions)	11.3	11.9	11.4	(5.0)%	4.4 %

2025 Compared to 2024

Coal and Limestone Operations net earnings increased \$16.4 million as a result of:

Operating revenue increased \$45.4 million mainly due to higher lignite coal sales of \$41.8 million resulting from higher average sales prices and higher lime sales of \$3.4 million.

Cost of products sold increased \$18.4 million primarily due to higher employee-related costs in lignite coal mining operations.

Selling, general and administrative increased \$1.1 million primarily due to higher freight expenses related to lime sales.

Depreciation and amortization increased \$2.6 million mainly due to investments in mining equipment.

Other income was comparable to 2024.

Interest and other charges, net increased \$2.3 million primarily due to higher debt balances resulting from investments in mining equipment.

Income tax expense was \$4.6 million higher largely due to higher income before taxes.

Earnings attributable to noncontrolling interest was comparable to 2024.

2024 Compared to 2023

Coal and Limestone Operations net loss increased \$2.2 million as a result of:

Operating revenue increased \$15.8 million mainly due to higher lignite coal sales of \$15.7 million due to increased volumes sold at higher average prices.

Cost of products sold increased \$8.0 million primarily due to higher employee-related costs in lignite coal mining operations.

Selling, general and administrative increased \$3.0 million primarily due to the absence of insurance proceeds received in 2023 of \$2.5 million.

Depreciation and amortization increased \$3.0 million mainly due to investments in mining equipment.

Other income was \$0.9 million higher largely due to unrealized gains on an investment fund and higher realized income on investments.

Interest and other charges, net increased \$3.2 million primarily due to higher debt balances resulting from investments in mining equipment.

Income tax benefit was comparable to 2023.

Earnings attributable to noncontrolling interest increased \$2.1 million mainly due to higher sales of lignite coal volumes to Dakota Coal.

Other Results

Other consists of the operations of Basin Cooperative Services, certain tax adjustments, intersegment eliminations, and other activity not associated with the Electric Utility, Gasification, and Coal and Limestone Operations segments. Basin Cooperative Services provides certain nonutility property management services to Basin Electric.

2025 Compared to 2024

The change in other is primarily related to the intersegment elimination of the increased loss at the Gasification segment. See “—*Gasification Results*” above for further detail on the increased loss.

2024 Compared to 2023

The change in other is primarily related to the intersegment elimination of the decreased loss at the Gasification segment. See “—*Gasification Results*” above for further detail on the decreased loss.

Liquidity and Capital Resources

General

Our liquidity is provided through a combination of cash generated from operations (including the operations of our subsidiaries), the MIP, the net proceeds of our financings and available commitments under existing credit facilities. While we fund operational costs with cash generated from our operations and our subsidiaries’ operations, we also issue commercial paper and periodically access our existing credit facilities to manage our liquidity. We also utilize the credit facilities to fund capital expenditures on an interim basis, which we intend to repay with the proceeds of the issuance of long-term debt secured under our Indenture.

Capital Resources

We had cash, restricted and designated cash and short-term investments of \$988.1 million as of December 31, 2025. This is inclusive of cash and investments of \$272.0 million designated for regulatory revenue deferrals as of December 31, 2025. Additionally, as of December 31, 2025, we had \$203.7 million of long-term investments. We believe these long-term investments could be liquidated promptly, therefore, we consider these investments as part of our liquidity position.

Our liquidity is supported by two revolving credit facilities. We have a \$1.25 billion unsecured syndicated revolving credit agreement. This facility is available for working capital purposes, including interim financing to fund capital expenditures, and supports a \$500 million taxable commercial paper program. Under the terms of the agreement, we have the right, subject to certain conditions, to increase the total amount of the facility by an additional \$250 million. This is a five-year facility with a maturity date of May 1, 2030. As of December 31, 2025, we had issued a letter of credit in the amount of \$250,000 with no amounts outstanding under this facility and no outstanding taxable commercial paper.

We also have a tax-exempt commercial paper program to support our liquidity. This program is supported by a \$100 million credit facility with National Rural Utilities Cooperative Finance Corporation (“CFC”), which may be used for liquidity to support commercial paper issuances and general corporate purposes. The facility expires on March 13, 2031. As of December 31, 2025, \$100.0 million of the CFC facility was used to support commercial paper issuances.

Both facilities contain customary terms and conditions affecting their availability. In addition, the facilities include covenants to maintain (i) an MFI Ratio for each fiscal year of at least 1.10, as calculated in accordance with the Indenture and (ii) a minimum equity balance as of the end of each fiscal quarter, in an amount no less than the greater of (a) 85% of our equity balance at the end of the next preceding fiscal year and (b) \$1 billion. For these purposes, our equity balance is calculated as our total members’ patronage capital or our other equity and that of our significant subsidiaries, less goodwill, as determined without duplication on a consolidated basis in accordance with GAAP, without giving effect to other comprehensive income or non-cash adjustments required to be made pursuant to accounting requirements.

We have a MIP available to all Class A and Class C Members. Under the MIP, we issue unsecured notes at short-term market rates with maturities ranging from overnight to two years. The MIP provides us with an additional source of capital and gives these member systems a flexible investment source. Funds borrowed from our members at any one time typically range from \$150 million to \$350 million. As of December 31, 2025, our obligations under the MIP totaled \$159.5 million.

We expect that financing for the projected capital expenditures of our subsidiaries principally will come from bank loans, private placements, leasing, and loans from us or from internally generated funds. In addition, we support our subsidiaries’ operations through the provision of credit facilities, including lines of credit to our subsidiaries, and guarantees.

The following table summarizes amounts outstanding under our lines of credit to our subsidiaries:

(In thousands)	Total Availability	Outstanding Amounts as of December 31, 2025
Dakota Gas	\$ 500,000	\$ 90,000
Dakota Coal	250,000	181,425
Basin Cooperative Services	3,000	-
Nemadji River Generation (a)	300,000	28,625
Total	\$ 1,053,000	\$ 300,050

(a) Nemadji River Generation, our wholly owned subsidiary, was formerly the owner of a 30% undivided interest in NTEC. In January 2026, Nemadji River Generation exited NTEC effective December 31, 2025.

Dakota Coal. In addition to our revolving credit facility, Dakota Coal issued a promissory note to us that it used for the expenditures associated with a truck dump and unit train load-out facility. As of December 31, 2025, \$14.1 million was outstanding under this note. Also, Dakota Coal issued two notes to us that it used for the expenditures associated with development of coal reserves. As of December 31, 2025, \$7.8 million was outstanding under these notes.

Cash Flows

Cash is provided by operating activities and issuance of debt. Capital expenditures comprise a significant use of cash.

(In thousands)	Years Ended December 31,		
	2025	2024	2023
Net cash provided by (used in)			
Operating activities	\$ 408,445	\$ 262,546	\$ 258,657
Investing activities	(678,549)	(266,782)	(217,016)
Financing activities	563,687	236,953	(82,917)
Net increase (decrease) in cash and cash equivalents and designated cash and equivalents	\$ 293,583	\$ 232,717	\$ (41,276)
Cash and cash equivalents and restricted and designated cash and equivalents, beginning of period	\$ 693,910	\$ 461,193	\$ 502,469
Cash and cash equivalents and restricted and designated cash and equivalents, end of period	\$ 987,493	\$ 693,910	\$ 461,193

2025 Compared to 2024

Operating activities. Net cash provided by operating activities increased \$145.9 million, primarily driven by the rate increase effective January 1, 2025 and lower recognition of previously deferred non-member revenue in 2025 of \$42.0 million. In addition, the timing of cash collected from receivables and payment of accounts payable and accrued expenses added to the increase in net cash provided by operating activities.

Investing activities. Net cash used in investing activities increased \$411.7 million largely due to \$162.1 million in incremental capital expenditures in 2025, largely related to additional investments in electric plant property. In addition, the net sales proceeds from investment funds decreased by \$257.4 million. The net proceeds were used in meeting the cash requirements of capital projects.

Financing activities. Net cash provided by financing activities increased \$326.7 million primarily due to the incremental issuance of \$336.7 million additional long-term debt compared to 2024 to support capital expenditures and proceeds of \$375 million from a short-term loan. The increase was partially offset by higher principal payments on long-term debt in 2025 compared to 2024 and the retirement of \$100 million in revolver borrowings. Additionally, we received \$167.5 million for the sale of certain membership interests in DCS in 2024.

2024 Compared to 2023

Operating activities. Net cash provided by operating activities increased \$3.8 million, primarily impacted by the timing of cash collected from receivables and payment of accounts payable and accrued expenses.

Investing activities. Net cash used in investing activities increased \$49.8 million largely due to \$120.5 million in incremental capital expenditures, largely related to additional investments in electric plant property. The increase in cash used was partially offset by increases in the net sales proceeds from investment funds of \$71.7 million. The proceeds were used in meeting the cash requirements of capital projects.

Financing activities. Net cash provided by financing activities increased \$319.9 million primarily due to the incremental issuance of \$399.6 million additional long-term debt compared to 2023 to support capital expenditures. The increase was partially offset by higher principal payments on long-term debt in 2024 compared to 2023. Additionally, we received \$167.5 million for the sale of certain membership interest in DCS in 2024.

Projected Capital Expenditures

Electric Utility

We annually forecast expenditures required for additional electric generation and transmission facilities and capital for enhancement of existing facilities. We review these projections frequently to update our calculations to reflect changes in our future plans, construction costs, market factors and other items affecting our forecasts. Our actual capital expenditures could vary significantly from these projections because of, among other things, unforeseen construction, changes in resource requirements, changes in actual or forecasted load growth, labor market uncertainty, weather or other issues. Our long-range capital plan details actual and projected construction requirements and system upgrades of approximately \$7.1 billion for the years 2026 through 2030, as follows:

	<u>2026</u>	<u>2027</u>	<u>2028</u>	<u>2029</u>	<u>2030</u>	<u>Total</u>
<i>(In millions)</i>						
New Generation	\$ 866	\$ 1,097	\$ 846	\$ 615	\$ 635	\$ 4,059
New Transmission	278	153	359	525	815	2,130
Existing Generation	233	186	30	47	72	568
Existing Transmission	54	75	49	31	30	239
Other Electric Projects	24	11	6	3	16	60
Total	<u>\$ 1,455</u>	<u>\$ 1,522</u>	<u>\$ 1,290</u>	<u>\$ 1,221</u>	<u>\$ 1,568</u>	<u>\$ 7,056</u>

The above table includes capital expenditures necessary to serve existing load as well as to serve our traditional load growth. It does not include expenditures to serve loads that qualify as large loads under our Large Load Commercial Program.

Some of the material projects included in the above detailed capital expenditures include:

- Bison Generating Station, a two-unit 1,470 MW combined-cycle gas generation plant with one unit expected to be commercial in 2029 and the other unit expected to be commercial in 2030;
- Several high voltage (230 kV and 345 kV) transmission line projects; and
- Initial expenditures for additional dispatchable natural gas generation in SPP and MISO market areas.

In order to meet the growing needs of our membership for power and energy we must continually add to and upgrade our generation and transmission resources. In addition to the specific projects enumerated in our table of projected capital expenditures, we are currently evaluating a number of other potential projects. Some of these additional projects may be pursued to completion and some may be abandoned. The numbers reflected for other projects in the table reflect our current estimate of what we may expend during the periods indicated on these types of projects. The amounts actually expended may

vary significantly from the estimates as some potential projects are abandoned and others are undertaken. Projects of this type which we are currently evaluating or pursuing include:

- Upgrades to existing generation;
- Additions and upgrades to existing high-voltage transmission and substation facilities in high growth areas; and
- Upgrades of existing facilities to ensure compliance with federal and state environmental regulations.

We anticipate that our projected capital expenditures will be funded by cash generated from operations, financed on an interim basis through commercial paper issuances and borrowings under our credit facilities, and with additional issuances of long-term debt with our relationship banks or in the private placement market and the capital markets. We expect that additional issuances of long-term debt will be secured under the Indenture. The timing and amount of these additional issuances will depend on the timing and amount of our capital expenditures, our cash generated from operations and balances on our revolving credit facilities.

Gasification

Construction and equipment requirements of Dakota Gas are projected to result in capital expenditures of approximately \$146 million over the period of 2026 through 2030.

We expect that Dakota Gas expenditures will be funded through advances on the existing \$500 million revolving credit facility with us. See “—*Capital Resources*.”

Coal and Limestone Operations

Mine development and equipment requirements of Dakota Coal are projected to result in capital expenditures of approximately \$262 million for the years 2026 through 2030.

We expect the mine development expenditures will be funded through Dakota Coal’s existing \$250 million revolving credit facility with us. See “—*Capital Resources*.” Major mobile equipment is expected to be financed through lease or debt financing.

Material Cash Requirements

Our cash requirements relate primarily to operating expenses, capital expenditures and debt service. As discussed above, we fund our cash requirements through a combination of cash generated from operations (including the operations of our subsidiaries), the MIP, the net proceeds of our financings and available commitments under existing credit facilities. For more information on our contractual obligations on long-term debt and purchase commitments, see Notes 11 and 18 to consolidated financial statements. At December 31, 2025, our material cash requirements include the following contractual and other obligations.

Debt. As of December 31, 2025, we had \$5.8 billion in outstanding obligations, with \$710.5 million payable in 2026. We have total future interest payments of \$3.8 billion, with \$273.2 million payable in 2026.

Coal Purchase Obligations. We, on behalf of the MBPP, have executed agreements with Western Fuels for all coal purchase requirements through the life of Laramie River Station and Dry Fork Generation Station, with an option to extend the contracts with approval by both parties. As of December 31, 2025, we had \$364.9 million in contractual obligations to purchase coal for our generating facilities under these agreements, with \$54.9 million payable in 2026.

Purchased Power Obligations. As of December 31, 2025, we had \$7.9 billion in contractual obligations to purchase power with terms ranging from one to 50 years, including \$423.9 million payable in 2026.

Contract Commitments. As of December 31, 2025, we had outstanding contractual commitments totaling \$2.9 billion for various construction projects, equipment purchases, supplies, and for miscellaneous services to be provided.

Credit Rating Triggers

Basin Electric Power Cooperative's senior secured debt and commercial paper have been assigned credit ratings by independent credit rating agencies. The current ratings are as follows:

	Senior Secured	Commercial Paper	Outlook
S&P	A	A1	Negative
Moody's	A3	P-2	Stable
Fitch	A	F1+	Stable

These credit ratings are based on rating criteria developed by each rating agency and reflect their respective assessments of Basin Electric's creditworthiness. Each rating agency applies its own methodologies, and the significance of a particular rating may differ among rating agencies. Credit ratings are not recommendations to purchase, sell, or hold securities, and do not address market price, liquidity, or the suitability of any security for a particular investor. Credit ratings may be revised or withdrawn at any time by the respective rating agencies.

We have financial agreements and commercial contracts containing provisions which, upon a credit rating downgrade below specified levels, may require the posting of collateral (in the form of either letters of credit, surety bonds or cash) or termination of the agreement.

In 2002 and 2003, we entered into three separate interest rate swaps with respect to certain variable rate First Mortgage Bonds due May 1, 2032 in the aggregate notional amount of \$150.0 million. In 2004, we entered into an interest rate swap with respect to one series of variable rate First Mortgage Bonds due June 10, 2030 (together with the First Mortgage Bonds due May 1, 2032, the "2008 Series A Notes") in the notional amount of \$50.0 million. These four interest rate swaps effectively change the interest rate on (i) \$100.0 million of our variable rate First Mortgage Bonds due in 2032 to a fixed rate of 6.18%, (ii) the remaining \$50.0 million of our variable rate First Mortgage Bonds due in 2032 to a fixed rate of 4.95% and (iii) \$50.0 million of our variable rate First Mortgage Bonds due in 2030 to a fixed rate of 5.33%.

Pursuant to the swaps entered into in 2002, 2003 and 2004, if our ratings from S&P or Moody's fall below the collateral ratings triggers of "A" or "A2," respectively, we are obligated to post collateral. If our ratings from S&P or Moody's fall below the termination ratings triggers of "BBB" or "Baa2," respectively, the swap counterparty has the right to terminate the swaps. In the event of a termination, either party could owe the other party a termination payment depending on the market value of the position of the swaps. We estimate that as of December 31, 2025, a termination of the four interest rate swaps entered into in 2002, 2003 and 2004 with respect to the 2008 Series A Notes would require us to make a termination payment of approximately \$22.0 million.

Other loan agreements may contain provisions based on credit ratings that could result in increased interest rates or restrictions on issuing debt but would not result in acceleration of any obligations or termination of any agreements.

Our management does not anticipate the occurrence of a ratings downgrade that would put our ratings below the termination triggers in any of our financial arrangements. Our ratings, however, reflect the views of the ratings agencies and not our views, and therefore we cannot give any assurance that our ratings will be maintained at current levels for any period of time.

Other Financing Arrangements

In 1985, we entered into six separate, but substantially identical, leveraged lease transactions of undivided interests in Antelope Valley Station Unit 2 and related common facilities. In these transactions, we sold an undivided interest in the facility to separate owner trusts for the benefit of six investors in exchange for an aggregate sales price of approximately \$622.9 million, funded through a combination of debt and equity. Immediately after the sale to each owner trust, we leased the undivided interests in Unit 2 and the related common facilities back and agreed to make periodic rental payments to such owner trust. The original term of each lease was scheduled to end on December 30, 2015, and were subsequently extended. We have certain renewal options and purchase options under each of these leases, including the option to purchase the undivided interest for an amount equal to the fair market sales value of the undivided interest. Effective August 11, 2015, we exercised the purchase option under three lease transactions and purchased a 24.2% interest in Antelope Valley Station Unit 2. The remaining leases have been extended through 2030. Upon the expiration of the leases, we will be obligated to operate Antelope Valley Station Unit 2 pursuant to an operating agreement if we do not agree to again extend the lease or exercise our option to purchase these interests.

Critical Accounting Estimates

Our consolidated financial statements are prepared in conformity with accounting principles generally accepted in the United States of America (“GAAP”). The preparation of consolidated financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the consolidated financial statements and the reported amounts of revenue and expenses during the reporting period. Estimates are used for items such as present value of lease assets and lease liabilities, plant depreciable lives, actuarially determined benefit costs, valuation of derivatives, asset retirement obligations, present value of expected tax credits, and income tax expense or benefits. Ultimate results could differ from those estimates.

We consider the following accounting policies to be critical accounting policies due to the estimation involved or due to the particular significance they have on our consolidated financial statements. Our critical accounting estimates are subject to judgments and uncertainties that affect the application of our significant accounting policies discussed in Note 2 to consolidated financial statements. As additional information becomes available, or actual amounts are determinable, the recorded estimates are revised. Consequently, our financial position or results of operations may be materially different when reported under different conditions or when using different assumptions in the application of the following critical accounting estimates.

Accounting for Section 45Q Transactions. As a part of the contractual agreements to monetize Section 45Q tax credits relating to carbon capture, utilization and sequestration of carbon dioxide from industrial facilities, Dakota Gas received an initial payment of \$167.5 million in 2024 from an investor and the right to receive installment payments in exchange for a membership interest in Dakota Carbon Services LLC (“DCS”). The initial payment was recognized in other current liabilities and other noncurrent liabilities on the consolidated balance sheets and the initial payment is accounted for as a sale of future revenue using the effective interest method. The carrying amount of the initial payment liability is the present value of the expected future tax credits to be earned. At December 31, 2025, 2024 and 2023, the initial payment liability was \$135.3 million, \$146.8 million, and \$0, respectively. When there is reasonable assurance that the tax credits will be earned, the initial payment liability is reduced and other income with an interest expense component is recorded. The present value of the expected future tax credits requires management to make estimates and assumptions related to the volumes of CO₂ that will be sequestered. These estimates and assumptions affect the reported amounts at the date of the consolidated financial statements. Ultimate results could differ from those estimates.

Regulatory Assets and Liabilities. We are subject to the provisions of ASC 980, Regulated Operations. Regulatory assets represent probable future revenue to us associated with certain costs

which will be recovered from customers through the ratemaking process. Regulatory liabilities represent probable future reductions in revenue associated with amounts that are to be credited to customers through the ratemaking process. At December 31, 2025, 2024, and 2023, regulatory assets were \$311.4 million, \$295.2 million, and \$305.0 million, respectively, and regulatory liabilities were \$336.3 million, \$337.2 million, and \$437.4 million, respectively. While we do not currently foresee any events or factors that would make it not probable that we will recover these costs from our members as future revenues through rates under our wholesale power contracts, if such an event were to occur, we could no longer apply the provisions of accounting for regulated operations, which would require us to eliminate all regulatory assets and regulatory liabilities that had been recognized as a charge or credit to our consolidated statements of operations and begin recognizing assets and liabilities in a manner similar to other businesses in general.

Derivative Financial Instruments. All derivatives are measured at fair value and recognized as either assets or liabilities on the consolidated balance sheets, except for derivative contracts that qualify for and are elected under the normal purchase and normal sales exception under the requirements of ASC 815, Derivatives and Hedging. We, Dakota Gas and Dakota Coal evaluate all purchase and sale contracts when executed to determine if they are derivatives and, if so, if they meet the normal purchase normal sale exception requirements under ASC 815. The derivative instruments that do not meet the normal purchase and normal sales exception are evaluated for designation as cash flow hedges of forecasted sales and purchases of commodities. We also utilize interest rate swap agreements to reduce exposure to interest rate fluctuations associated with floating rate debt obligations and anticipated debt financing.

Under ASC 980, our Board defers changes in the fair value of certain utility derivative activity as a regulatory item to be recovered through rates in the future. Only current settlements of these derivative transactions are included in earnings. See “*Regulatory Assets and Liabilities*” above. These amounts are subsequently reclassified as operating expense or interest expense on our consolidated statements of operations as the power or fuel is delivered and/or the contract settles.

Derivatives are reported at fair value on our consolidated balance sheets. The measurement of fair value is based on actively quoted market prices, if available. Otherwise, we seek indicative price information from external sources, including industry publications. The fair value of the derivatives requires management to make estimates and assumptions that affect the reported amounts at the date of the consolidated financial statements. Ultimate results could differ from those estimates.

For additional information, see “[QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK](#)” and Note 8, “Derivative Financial Instruments” and Note 14, “Assets and Liabilities Measured at Fair Value” to the consolidated financial statements.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Our Risk Management Steering Committee (“RMSC”) consists of members of our and our subsidiaries’ management teams who review and govern all commodity transactions’ associated risks for us and our subsidiaries. Our risk management policy contains a framework that defines risk parameters, delineates management responsibility and establishes organizational relationships to ensure appropriate checks and balances. Among other things, RMSC is responsible for reviewing our and our subsidiaries’ risk profiles and performance, setting our risk strategies and risk management policies with respect to market, credit, liquidity and model risks, and reporting these risk management activities to our Board and the Dakota Gas and Dakota Coal boards of directors. In addition to direct oversight by RMSC, certain risk management functions and responsibilities have been delegated by RMSC to various risk management groups and other personnel within the organization.

Risk Policies

We and our subsidiaries are exposed to several market risks that could have a material impact on our revenue, expense, and investment balances. Commodity prices for natural gas, electricity, urea, crude oil, tar oil, diesel, DEF and anhydrous ammonia are the most significant of the commodity price risks due to either the high degree of volatility, the high volumes of the commodity we transact, the downstream impacts the pricing has on our other commodities (correlation), or any combination thereof. We are exposed to increasing interest rates. Because we and our subsidiaries are asset intensive, increasing interest rates can have a material impact on the interest expense paid for capital funding. We are exposed to equity price risks related to the changing prices of equities we hold as investments relating to various mine closing, asset retirement and decommissioning funds.

We believe that we have adequate safeguards, reporting mechanisms, and procedures in place to protect us and our subsidiaries from many but not all market risks. We and our subsidiaries have certain risk management strategies relating to the sales and purchase prices of commodities to provide insulation from volatile market prices. To manage our market risks, we may enter into various derivative instruments, including swaps, forward contracts, futures contracts, and options. Our Board has also established guidelines that are intended to ensure that derivatives and other financial instruments are used only for hedging purposes and not for speculation.

Interest Rate Risk

We are exposed to risk resulting from changes in interest rates as a result of the use of variable rate debt as a source of financing as well as the fixed income investments in our various portfolios. We manage our interest rate exposure by limiting the total amount of our variable rate exposure to within a particular percentage range of our total debt and by actively monitoring the effects of market changes in interest rates. As of December 31, 2025, all of our outstanding long-term indebtedness secured under the Indenture accrued interest at fixed rates to their final maturity, either inherently or through swaps, except for \$100 million. The fair market value of Basin Electric’s interest rate swaps was a loss of \$22.0 million as of December 31, 2025.

As of December 31, 2025, our long-term and short-term debt subject to variable interest rates totaled \$756 million. As a stress test, we considered the increased interest expense of an increase of 100 basis points to the weighted average interest rate. The result of this analysis would have been approximately \$7.6 million of increased interest expense annually, not considering any increase in investment interest income we would gain to offset the increased expense or changes to principal amounts outstanding.

In addition to interest rate risk on existing debt, we are exposed to the risk of rising interest rates due to the new long-term debt we expect to incur in connection with anticipated capital expenditures as well as short-term debt we plan to use for interim financing on various projects. The interest rates on these future issuances are largely unhedged and we are exposed to risks in fluctuations of the underlying index rates as well as spreads over those rates. We periodically enter into financial derivative instruments,

which may include instruments such as, but not limited to, interest rate swaps, swaptions and U.S. Treasury lock agreements to mitigate a portion of this interest rate risk.

Commodity Price Risk

Electric Utility Operations

We serve member load requirements in various distinct planning areas primarily within: SPP, MISO, and Western Power Pool (“WPP”). Both SPP and MISO function as regional transmission organizations while WPP is within the WECC bilateral market. The majority of our member load requirement is held between SPP and WECC. Power prices in the power markets are largely driven by weather related demand which drives load levels, natural gas pricing and increasing levels of renewable generation build outs. We continually meet our resource adequacy requirements to provide generating capacity to meet our full member load requirements. The regional transmission organization market offers a benefit of dispatching the most economic resources and transmission available. We have enough generation to serve our member load requirements in WPP and any excess generation is sold to produce non-member revenue which helps to lower the overall member rate.

The price of power is particularly sensitive to the build out of renewable generation and volatile natural gas prices. Several factors influence natural gas price levels and volatility. These factors include, but are not limited to, seasonal changes in demand, weather conditions, transportation availability and reliability within and between regions, fuel availability, market liquidity, global market impacts, and the nature and extent of current and potential federal and state regulations.

With respect to our power sales, our Board has established guidelines for the use of derivative instruments. Those guidelines include but are not limited to (i) hedging activity shall be used only to mitigate risk or optimize returns on owned or operated assets and be non-speculative in nature, (ii) derivatives may not be longer than five years in tenor or duration unless approved by our Board, and (iii) risk management status and performance must be reported to our Board on a periodic basis. As of December 31, 2025, we have entered into a series of floating-to-fixed swap agreements for natural gas and power to manage the variable price risk associated with a portion of forecasted commodity exposure through December 2033. As of December 31, 2025, the fair market value of Basin Electric’s swaps was a loss of \$29.5 million.

Gasification Operations

With respect to commodity price risks at Dakota Gas associated with the varying market prices of commodities, management established a program that is in accordance with certain policies approved by the Dakota Gas board of directors, including that: (i) hedging activity shall be used only to mitigate risk or optimize returns on owned or operated assets and be non-speculative in nature, (ii) derivatives may not be longer than five years in tenor or duration unless approved by the Dakota Gas board of directors and (iii) risk management status and performance must be reported to the Dakota Gas board of directors on a periodic basis.

We have a natural hedge with Dakota Gas against fluctuations in natural gas prices for a portion of the volumes burned by us that is offset by volumes produced by Dakota Gas. We and Dakota Gas consider this natural hedge when determining the amount of financial or physical hedges to put in place. Dakota Gas does not currently have derivative financial instruments outstanding for the purpose of mitigating the risk of market price fluctuations for urea, DEF, or power; however, Dakota Gas does have floating-to-fixed swap agreements in place to mitigate price fluctuations for the sale of natural gas and tar oil through November 2027. The fair market value of the swaps at December 31, 2025 was a gain of \$7.0 million.

Coal and Limestone Operations

Dakota Coal has entered into derivative financial instruments for the purpose of mitigating the risk of market fluctuations in the price of diesel for the coal costs paid to Coteau through December 2028. The fair market value of the derivative instruments was a loss of \$2.0 million at December 31, 2025.

Credit Risk

We are exposed to credit risk, primarily through potential losses that may result from a counterparty's nonperformance. We and our subsidiaries use credit policies to control our credit risk associated with credit sales of energy and gas commodities and derivatives, including utilizing a credit approval process, monitoring counterparty limits and ensuring that our counterparty has an adequate credit rating. However, due to the possibility of extreme volatility in the prices of energy and gas commodities and derivatives, the market value of contractual positions with individual counterparties could exceed established credit limits or collateral provided by those counterparties. If such a counterparty were then to fail to perform its obligations under its contract (for example, fail to pay for power or gas that we or Dakota Gas had delivered), we could sustain a loss that could have a material impact on our financial results.

Equity and Debt Security Price Risk

We are exposed to price and interest rate fluctuations in equity and debt markets through investment in equity and debt securities relating to various mine closing, asset retirement, and decommissioning funds. As of December 31, 2025, our aggregate investment in equity funds for these various funds was \$203.6 million. To minimize adverse changes in the aggregate value of the funds, we actively monitor our portfolios by measuring the performance of the investments against market indices and by maintaining and reviewing established target allocation percentages of assets in the funds to various investment options. We do not believe our exposure to fluctuations in prices of equity and debt securities we hold will have a material impact on our financial results.

LEGAL PROCEEDINGS

For a discussion of legal proceedings involving Basin Electric, see Note 18, "Commitments and Contingencies—Legal" to the consolidated financial statements.

DIRECTORS, EXECUTIVE OFFICERS, AND CORPORATE GOVERNANCE

Corporate Governance

Our corporate powers are vested in an eleven-member Board, which meets monthly. Each of our ten G&T Class A Members elects and is represented by one member on the Board. The eleventh member of the Board is elected by and represents the nine distribution Class A Members and the one Class D Member. Class B and C Members are represented by the directors of the Class A Members from whom they receive their power. The directors serve for three-year terms on a staggered basis, and must serve on their respective Class A, and except for District 9, Class C Member boards, while holding a board seat on our Board. This service requirement helps ensure that members of the Board have business experience related to the electric cooperative industry in addition to an interest in the successful operation of our business. We have no direct role in the nomination of candidates or the election of members to the Board by our members. We believe that this board structure further strengthens our cooperative model and ensures our Board members are also our owner-customers.

Because we are a cooperative, our members own us and, in accordance with our bylaws, all of our directors are representatives of our Class A Members and each of our directors serves as a director of the Class A Member that such director represents on the Board. Our bylaws prohibit our directors from being employed by or financially interested in a competing enterprise or business selling electric energy or supplies to us. In addition, our bylaws provide that no person is eligible to serve on the Board if any member of his or her immediate family is then employed by us. In addition to meeting the requirements set forth in our bylaws, all of our current directors and members of the audit committee of the Board satisfy the applicable independence standards established by the Nasdaq Stock Market. Although we do not have any securities listed on the Nasdaq Stock Market, the Board used its independence criteria to make this determination in accordance with applicable SEC rules.

Director and Executive Officer Biographies

Our directors and executive officers, and their ages as of April 15, 2026, are as follows:

Name	Age	Position
Directors:		
Wayne Peltier	76	President and Director–District 9
Paul Baker	60	Vice President and Director–District 10, Members 1st Power Cooperative
Tom Wagner	61	Secretary/Treasurer and Director–District 4, Northwest Iowa Power Cooperative
Leo Brekel	74	Assistant Secretary and Director–District 5, Tri-State G&T Association
Jerry Beck	83	Director–District 11, Corn Belt Power Cooperative
Daniel Gliko, Jr.	59	Director–District 6, Central Montana Electric Power Cooperative
Anthony Larson	52	Director–District 8, Upper Missouri Power Cooperative
David Meschke	69	Director–District 2, L&O Power Cooperative
Kermit Pearson	79	Director–District 1, East River Electric Power Cooperative
Troy Presser	61	Director–District 3, Central Power Electric Cooperative
Executive Officers:		
Todd Brickhouse	54	Chief Executive Officer and General Manager
Christopher Johnson ..	55	Senior Vice President and Chief Financial Officer
Chris Baumgartner	53	Senior Vice President of Member and External Relations
Gavin McCollam	61	Senior Vice President and Chief Operating Officer
Miles McGrew	54	Senior Vice President and Chief Human Resources Officer
Jim Horan	46	Senior Vice President and General Counsel
Val Weigel	47	Senior Vice President of Energy Markets and Dakota Coal Operations
Trinity Turnbow	45	Vice President and Plant Manager at Dakota Gasification Company

Directors

Wayne A. Peltier, President was appointed to the Board in April 2008. He holds a directorship in Minnesota Valley Cooperative Light and Power Association and represents District 9. He has 21 years of experience in the electric cooperative industry. He is an owner and operator of a farm in Southwest Minnesota. Also, he owns and operates a metal fabrication business in Cottonwood, MN.

Paul L. Baker, Vice President was seated on the Board in 2013. Mr. Baker has been an electric cooperative board member since 1994. He holds a directorship on the PRECorp and Members 1st Power Cooperative boards. Mr. Baker earned a Bachelor of Science in finance from the University of Wyoming. He owns and operates a cattle ranch named Raven Creek Ranch.

Tom J. Wagner, Secretary/Treasurer was seated on the Board in 2017 representing District 4, Northwest Iowa Power Cooperative. Tom also holds a directorship in North West Rural Electric Cooperative. He is the O’Brien County Soil & Water District Commissioner. He is an owner and operator of a farm in northwest Iowa.

Leo N. Brekel, Assistant Secretary and Director was seated on the Board in 2014. Mr. Brekel holds a directorship on the Highline Electric Association and Tri-State boards. He has been an electric cooperative board member since 1995. Mr. Brekel has served on Tri-State’s board since 2003 and serves as a member of Tri-State’s Finance and Audit Committee. He is a wheat farmer near Fleming, Colorado.

Jerry R. Beck, Director became a member of the Board in December 2021. Mr. Beck, who represents Corn Belt, also holds a directorship in Iowa Lakes Electric. Mr. Beck has 20 years of experience in the electric cooperative industry. He is an owner and operator of a farm in northwest Iowa.

Daniel A. Gliko, Jr., Director was seated on the Board in 2017 representing District 6, Central Montana. He has been an electric cooperative board member since 2001. He is currently a Territory Sales Manager for BTI Montana.

Anthony D. Larson, Director became a Board member in 2024. Mr. Larson, who represents Upper Missouri Power Cooperative, is also the Treasurer at Upper Missouri Power Cooperative. He has served on the board of electric cooperatives since 2010. Also, Mr. Larson has served on CFC's board since 2020 and serves as a member of CFC's Audit and Financial Advisory Committees. He owns and operates a cattle ranch named 1910 Larson Ranch.

David E. Meschke, Director was seated on the Board in 2017 representing District 2, L&O Power. He is a certified credentialed director through the National Rural Electric Cooperatives Association. He is currently a Claims Manager for Rural Community Insurance Services (RCIS).

Kermit M. Pearson, Director has served as a member of the Board for 24 years. Mr. Pearson also holds a directorship with Lake Region Electric Association, Inc. and East River. He has 40 years of experience in the electric cooperative industry. Mr. Pearson earned a Bachelor of Science from South Dakota State University. He is a self-employed farmer and rancher in northeastern South Dakota.

Troy E. Presser, Director was seated on the Board in 2015. Mr. Presser holds a directorship on the McLean Electric Cooperative and Central Power Electric Cooperative boards. He has been an electric cooperative board member since 2007. Mr. Presser studied agriculture economics at North Dakota State University. He is a self-employed farmer and rancher of Presser Red Angus.

Executive Officers

We are organized into major line departments which report to the Chief Executive Officer and General Manager.

Todd T. Brickhouse is our Chief Executive Officer and General Manager and has served in such role since July 2023, initially in an interim capacity. He joined Basin Electric in June 2022 as Senior Vice President and Chief Financial Officer. Mr. Brickhouse has more than 25 years of experience in finance, risk management, and strategic planning in the utility industry, including 21 years at Old Dominion Electric Cooperative. Mr. Brickhouse holds a B.A. in Economics and Business from the Virginia Military Institute in Lexington, Virginia.

Christopher A. Johnson is our Senior Vice President and Chief Financial Officer and joined Basin Electric in 2024. He is responsible for accounting, finance and treasury, insurance, procurement and power supply planning and rates. Prior to accepting this position, he spent 10 years at Tri-State Generation and Transmission Association in Westminster, Colorado, where he served as Vice President of Finance. He has 30 years of finance and accounting experience in the utility industry and holds an M.B.A from the University of Georgia, as well as a B.B.A in Accounting from Georgia State University.

Christopher "Chris" L. Baumgartner is our Senior Vice President, Member and External Relations and is responsible for member services, strategic planning, and communications for the cooperative. He has been employed with Basin Electric and electric cooperatives since 1992. From 2012 until 2017, he served as co-general manager/CEO of Innovative Energy Alliance. He has a Master of Business Administration, Master of Management, and a Bachelor of Science from the University of Mary, Bismarck, North Dakota.

Gavin A. McCollam is our Senior Vice President and Chief Operating Officer and joined Basin Electric in 1989. He is responsible for our generation, transmission, engineering, construction, and environmental operations. He holds a Masters in Systems Management from the University of Southern California, Los Angeles, as well as a Bachelor of Science in Mechanical Engineering from North Dakota State University.

Miles M. McGrew is our Senior Vice President and Chief Human Resource Officer and has been employed with Basin Electric since 2022. He is responsible for our human resources, information technology, safety, and security operations. Prior to accepting this position, McGrew worked most recently as the vice president of human resources for Seaboard Triumph Foods, a Sioux City, Iowa company. He has more than 25 years of experience in human resources, international labor relations, mergers and acquisitions, and organizational development. He holds a Masters in Public Health from the University of Illinois, Springfield, as well as a Bachelor of Science in Labor Relations from Sangamon State University, Springfield.

James “Jim” Horan is our Senior Vice President and General Counsel and joined Basin Electric in 2025 and is responsible for all legal matters and has experience with distribution, statewide, regional, and national cooperative utility entities. Prior to accepting this position, he served as Executive Director of Mid-West Electric Consumers Association, where he represented the interests of its consumer-owned utilities for five years. Mr. Horan holds a Juris Doctor from William Mitchell College of Law, and a B.A. from Saint Mary’s University.

Valerie “Val” A. Weigel is our Senior Vice President of Energy Markets and Dakota Coal Operations and has been employed with Basin Electric since 1998. She oversees market strategy and optimization, commodity management including purchases, sales and risk mitigation, and coal and limestone operations. She holds a Master of Business Administration from the University of North Dakota in Grand Forks and a Bachelor of Science in Business Administration from the University of Mary in Bismarck. Valerie is a voting member of the Southwest Power Pool Western Market Executive Committee and is on the Lignite Energy Council board.

Trinity J. Turnbow is our Vice President and Plant Manager at Dakota Gasification Company and has been employed at Dakota Gasification Company since 2008. He holds a Bachelor of Science in Chemical Engineering from the University of Minnesota, Twin Cities.

EXECUTIVE COMPENSATION

Compensation Discussion and Analysis

For fiscal year 2025, our named executive officers (“NEOs”) consist of the individuals listed below:

- Todd Brickhouse, Chief Executive Officer and General Manager
- Christopher Johnson, Senior Vice President and Chief Financial Officer
- Chris Baumgartner, Senior Vice President of Member and External Relations
- Gavin McCollam, Senior Vice President and Chief Operating Officer
- Miles McGrew, Senior Vice President and Chief Human Resource Officer
- Mark Foss, Former Senior Vice President and General Counsel

General Philosophy

Basin Electric’s executive compensation philosophy is reviewed periodically by the Board of Directors and is designed to align executive pay with the cooperative’s mission, operational complexity, and long-term financial stewardship. This philosophy is intended to provide a consistent framework for evaluating executive compensation decisions while allowing flexibility to address role scope, experience, performance, and retention considerations.

The executive compensation philosophy is based on the following principles:

- Mission alignment
- Market competitiveness
- Pay-for-performance
- Internal equity
- Financial stewardship

Market Benchmarking Approach. Basin Electric benchmarks executive compensation against not-for-profit utilities, cooperative organizations, and investor-owned utilities of similar size and operational complexity:

- Use of a blended utility market reflecting the executive talent pool
- Biennial executive market benchmarking, supported by interim monitoring and Board oversight
- Market targeting around the median with flexibility for role scope and retention
- Use of external advisors as appropriate

Governance of Executive Compensation. The compensation of executive officers is determined by:

- Board of Directors
 - Approves CEO compensation and the executive compensation philosophy
- Chief Executive Officer
 - Oversees compensation for the executive leadership team

- Conducts performance evaluations and recommends adjustments
- HR, Finance, Legal
 - Ensure program compliance, documentation quality, and internal equity
 - Support the administration and governance of compensation programs
- External Advisors
 - Provide benchmarking, governance, and compensation design guidance

Performance Management. The Board evaluates the CEO; the CEO evaluates all other executives. Performance Management includes:

- Annual goal setting
- Ongoing Executive performance discussions
- Year-end evaluations

Performance evaluations are considered as one of several factors in executive compensation decisions, consistent with the approved compensation philosophy.

Components of Executive Total Compensation.

The executive compensation framework of Basin Electric includes base salary, retirement benefits (including split-life insurance arrangements), deferred compensation, and health and welfare benefits. Health and welfare benefits are provided pursuant to Basin Electric's broad-based employee benefit programs.

Base Salary. Base salary represents the primary form of fixed compensation for our named executive officers. Base salaries are established based on the scope and responsibilities of the position, the executive's experience and qualifications, internal equity considerations, and relevant market data. Base salary levels are reviewed periodically and may be adjusted to reflect changes in responsibilities, individual performance, and market competitiveness.

Short-Term Incentive Compensation. Basin Electric does not maintain a formal short-term incentive for its NEOs.

Equity-Based Compensation. As an electric cooperative without capital stock, Basin Electric does not provide equity-based compensation, such as stock options, restricted stock, or other stock-based awards.

Split-Life Insurance. Basin Electric maintains a legacy split-dollar life insurance arrangement for a limited group of employees, including certain named executive officers. Participation is limited to individuals who were participants as of July 1, 2001. Under this arrangement, Basin Electric pays premiums on life insurance policies, and the executive receives an economic benefit associated with the coverage.

Perquisites and Other Benefits. We generally do not provide significant perquisites or personal benefits to our NEOs.

Named executive officers participate in benefit programs generally available to employees, including health and welfare, and retirement programs. Any additional compensation provided outside of base salary is limited and is disclosed, as applicable, in the Summary Compensation Table under "All Other Compensation".

Retirement Benefits. Executives participate in the following programs:

- *Defined Benefit Pension Plan.* Provides lifetime retirement benefits based on eligible compensation and credited service, subject to IRS compensation and benefit limitations. The NRECA Retirement Security Plan (the “RS Plan”) is closed to new entrants and was frozen for affected participants in 2018, which will result in declining future benefit accruals under both the RS Plan and the Executive Benefit Restoration Plan (the “EBR Plan”).

- *401(k) Plans with Employer Contributions.* Executives may defer compensation subject to IRS limits, and Basin Electric provides employer contributions consistent with plan provisions.

Nonqualified Deferred Compensation Programs: To supplement retirement benefits and restore limited amounts under IRS rules, Basin Electric offers the following:

- *Homestead Deferred Compensation Plan (“Homestead Plan”)*– Provides nonqualified deferred retirement benefits to a closed group of designated management or highly compensated employees based on amounts specified for each participant. Participation is limited to employees designated by the Board prior to January 1, 2015. This plan is funded by Basin Electric and plan participants are paid either installments or a lump sum based on their distribution election or plan provisions.
- *Executive Deferred Compensation Plan (“EDCP”)* – A nonqualified deferred compensation plan that allows executives designated under the plan’s top-hat eligibility criteria to defer compensation and receive employer contributions that mirror the applicable 401(k) match formula on compensation above IRS limits, with additional discretionary contributions permitted under the plan.
- *Executive Benefit Restoration Plan (“EBR Plan”)* – Provides supplemental retirement benefits for executives who participate in the RS Plan by restoring pension amounts that cannot be provided under the qualified plan due to IRS compensation and benefit limitations. Eligibility for the EBR Plan is restricted to RS Plan participants, and benefit formulas vary based on RS Plan provisions applicable to each participant.

Executive Compensation

The following tables provide detailed information regarding compensation earned by or paid to our NEOs for fiscal year 2025.

Summary Compensation Table

The following table sets forth information concerning compensation awarded to, earned by or paid to our NEOs for fiscal years 2025, 2024 and 2023, as applicable. The table also identifies the principal capacity in which each of these executives serves or served.

Name and principal position	Year	Salary (\$)	Change in pension value and nonqualified deferred compensation earnings (\$) ⁽¹⁾	All other compensation (\$) ⁽²⁾	Total (\$)
Todd Brickhouse	2025	1,500,000	426,188	52,500 ⁽³⁾	1,978,688
Chief Executive Officer and General Manager	2024	1,480,769	381,211	51,750	1,913,730
	2023	707,692	182,186	92,211	982,089
Christopher Johnson	2025	569,813	91,704	49,350 ⁽⁴⁾	710,867
Senior Vice President and Chief Financial Officer	2024	450,481	21,368	128,065	599,914
Chris Baumgartner	2025	452,472	343,102	21,000 ⁽⁵⁾	816,574
Senior Vice President of Member and External Relations	2024	440,325	161,487	20,700	622,512
	2023	425,000	—	19,800	444,800
Gavin McCollam	2025	452,653	165,215	17,500 ⁽⁶⁾	635,368
Senior Vice President and Chief Operating Officer	2024	440,487	116,113	17,250	573,849
	2023	397,629	4,009	16,500	418,138
Miles McGrew	2025	461,777	87,133	52,500 ⁽⁷⁾	601,410
Senior Vice President and Chief Human Resource Officer	2024	449,041	78,132	51,750	578,923
	2023	392,308	38,908	49,414	480,629
Mark Foss ⁽⁹⁾	2025	456,429	209,689	16,406 ⁽⁸⁾	682,524
Former Senior Vice President and General Counsel	2024	476,100	121,809	15,260	613,168
	2023	460,000	—	16,500	476,500

- (1) Amounts reported represent the annual increase, if any, in the aggregate value of benefits accrued under Basin Electric's retirement and nonqualified deferred compensation plans, calculated in accordance with the terms of the applicable plans and agreements. Negative changes in value are not reflected. The plans are maintained pursuant to their respective governing documents, which set forth eligibility, benefits, and other terms and conditions.
- (2) Amounts reported include the taxable value of Basin-provided meals, rewards paid, taxable flights, the taxable economic benefit and any related gross-up associated with split-dollar life insurance coverage, if applicable, relocation benefits, if applicable, employer matching contributions to Basin's 401(k) plan, and other miscellaneous benefits, including volunteer- and housing-related items.
- (3) For Mr. Brickhouse, this amount represents \$52,500 for employer 401(k) plan contributions.
- (4) For Mr. Johnson, this amount represents \$49,350 for employer 401(k) plan contributions.
- (5) For Mr. Baumgartner, this amount represents \$21,000 for employer 401(k) plan contributions.
- (6) For Mr. McCollam, this amount represents \$17,500 for employer 401(k) plan contributions.
- (7) For Mr. McGrew, this amount represents \$52,500 for employer 401(k) plan contributions.
- (8) For Mr. Foss, this amount represents \$16,406 for employer 401(k) plan contributions.
- (9) Mr. Foss's employment with Basin Electric as Senior Vice President and General Counsel ended on November 18, 2025. Mr. Foss continues to serve Basin Electric in a quasi-retirement arrangement as a Senior Legal Counsel.

Defined Benefit Plan

The following table lists the estimated actuarial present values of accumulated benefits under the RS Plan and the EBR Plan as of December 31, 2025. The RS Plan provides a defined benefit based on

credited service and final average compensation, subject to IRS limitations. The RS Plan is closed to new entrants hired after January 1, 2018. The EBR Plan restores the portion of pension benefit that cannot be provided under the RS Plan due to IRS compensation and benefit limitations. Eligibility for EBR is limited to employees who participate in the RS Plan, and EBR benefit formulas correspond to the RS Plan provisions applicable to each participant and may vary based on date of hire.

Name	Number of years Credited Service as of December 31, 2025	RS Plan Present Value of Accumulated Benefit as of	EBR Plan Present Value of Accumulated Benefit as of	Payments During
		December 31, 2025 (\$)	December 31, 2025 (\$)	2025
Chris Baumgartner	29 Years 11 Months	1,761,614	509,933	None
Gavin McCollam	25 Years 10 Months	2,464,474	264,923	None
Mark Foss ⁽¹⁾	11 Years 7 Months	975,469	325,619	None

(1) Mr. Foss participates in a quasi-retirement arrangement under which he continues to accrue benefits under the RS Plan and the EBR Plan while remaining employed. The amounts shown for Mr. Foss represent the estimated actuarial present value of benefits accrued under the RS and EBR Plans as of December 31, 2025. No pension payments were made to Mr. Foss during 2025.

The pension benefits indicated above are the estimated amounts payable under the RS Plan and the EBR Plan, and they are not subject to any deduction for Social Security or other offset amounts. A participant's annual pension at normal retirement age is equal to the product of the participant's years of credited service multiplied by the average of the participant's highest annual salary in five of the last ten years multiplied by one or two percent based on hire date. The value listed in the table is the actuarial lump-sum amount that would have been payable to the participant if employment had terminated on December 31, 2025.

Nonqualified Executive Deferred Compensation Plan

As described above, eligible executives may participate in Basin Electric's nonqualified deferred compensation arrangements, including the Homestead Plan, the EDCP, and the EBR Plan. The Homestead Plan is closed to new entrants, and all but one remaining participant are in paid status. The EDCP is available to executives designated under the plan's top-hat eligibility criteria. The following table lists the contributions made to the EDCP during the last fiscal year and the account balances as of December 31, 2025.

Name	Executive contributions in last fiscal year (\$) ⁽¹⁾	Our contributions in last fiscal year (\$) ⁽²⁾	Aggregate earnings in last fiscal year (\$) ⁽²⁾	Aggregate withdraws/distributions (\$)	Aggregate balance as of fiscal year end (\$) ⁽³⁾
Todd Brickhouse	200,000	222,501	203,687	—	1,854,186
Christopher Johnson	10,577	81,732	9,972	—	130,456
Chris Baumgartner	25,000	81,114	171,002	—	1,193,103
Gavin McCollam	10,207	5,104	5,080	—	43,326
Miles McGrew	5,559	66,678	20,454	—	219,488
Mark Foss	95,500	5,634	155,803	—	1,303,443

(1) Amounts deferred under the EDCP for each of the NEOs have been reported as 2025 compensation to such NEOs in the "Salary" column in the Summary Compensation Table.

(2) Amounts reported are reflected, as applicable, in the Summary Compensation Table within the column titled "Change in pension value and nonqualified deferred compensation earnings." The amounts presented in this

table represent account activity and balances under the applicable nonqualified deferred compensation plans and should not be aggregated with the amounts reported in the Summary Compensation Table.

- (3) Includes the following amounts deferred by each NEO in 2025 and prior years, including contributions by Basin Electric to the applicable nonqualified deferred compensation plans:

Name	Homestead Plan (\$)	EDCP (\$)	EBR Plan (\$)
Todd Brickhouse	—	1,854,186	—
Christopher Johnson	—	130,456	—
Chris Baumgartner	—	1,193,103	509,933
Gavin McCollam	—	43,326	264,923
Miles McGrew	—	219,488	—
Mark Foss	65,967	1,303,443	325,619

Employment Agreement

We have an employment agreement with Mr. Brickhouse, which is dated December 22, 2025 and has a three-year term. The agreement sets forth his annual base salary, participation in Basin Electric’s benefit plans, and severance protections applicable upon certain terminations of employment. It also provides eligibility for Basin Electric’s retirement and deferred compensation programs in accordance with their terms. The agreement outlines the duties associated with his role as Chief Executive Officer and includes customary provisions regarding confidentiality and termination. Mr. Brickhouse’s employment may be terminated by Basin Electric with or without “cause,” and he may resign with or without “good reason” (as such terms are defined in the agreement) by 30 days written notice. We have not entered into employment agreements with other NEOs.

Potential Payments Upon Termination or Change-in-Control

Basin Electric maintains severance arrangements with certain active NEOs that provide for payments upon a qualifying termination of employment. No severance payments were made during fiscal year 2025.

Pursuant to Mr. Brickhouse’s employment agreement, in the event of a termination of his employment by Basin Electric without “cause” or by Mr. Brickhouse with “good reason”, he is entitled to the following: (i) continued payment of his base salary for a one-year period, and (ii) reimbursement for premiums paid by the executive for medical insurance pursuant to the Consolidated Omnibus Budget Reconciliation Act (“COBRA”) during the one-year period.

Under these severance arrangements with each of Messrs. Johnson, Baumgartner, McCollam, and McGrew, if a NEO were terminated without “cause” as of December 31, 2025, such executive would be entitled to a cash severance payment equal to twelve months of base salary, payable in accordance with the applicable agreement.

The estimated cash severance amounts that would have been payable to the active NEOs as of December 31, 2025, based solely on base salary then in effect, are as follows:

Name	Estimated Severance (12 Months Base Salary) (\$)
Todd Brickhouse	1,500,000
Christopher Johnson	575,016
Chris Baumgartner	455,396
Gavin McCollam	456,123
Miles McGrew	465,316

There is no employer-provided subsidy for the COBRA premium.

Compensation Committee Interlocks and Insider Participation

As described above, the entire Board approves the compensation for our Chief Executive Officer and the Board has delegated to our Chief Executive Officer the authority to establish and adjust compensation for all other executive officers. None of our executive officers served on any board of directors or compensation committee of any other entity that has or has had one or more executive officers who served as a member of the Board during the year ended December 31, 2025.

Chief Executive Officer Pay Ratio

We strive to provide fair and equitable compensation to each of our employees through a combination of competitive base pay, retirement programs, and other benefits. The following information compares the annual total compensation of Mr. Brickhouse, our Chief Executive Officer and General Manager, to the annual total compensation of our median employee for the 2025 fiscal year. The 2025 compensation disclosure ratio of the annual total compensation of our Chief Executive Officer to the annual total compensation of our median employee is as follows:

Category and Ratio	2025 Total Compensation
Median annual total compensation of all employees (excluding Chief Executive Officer)(1)	\$ 118,152
Annual Total Compensation of Todd Brickhouse, Chief Executive Officer	\$ 1,978,688
Ratio of the median annual total compensation of all employees to the annual total compensation of Todd Brickhouse, Chief Executive Officer	1.0:16.7

(1) To identify our median employee, we used our employee population as of December 13, 2025, and calculated total compensation for that population in accordance with SEC rules, in the same manner as the amount set forth in the “Total” column in the Summary Compensation Table, using payroll information through December 13, 2025, reflecting 26 pay periods. While the methodology involves several assumptions and adjustments, we believe the pay ratio information set forth above constitutes a reasonable estimate, calculated in a manner consistent with the SEC Rules. Due to estimates and assumptions permitted under SEC rules, our pay ratio disclosure may not be comparable to the pay ratio disclosure presented by other companies. As of December 13, 2025, we considered our entire employee population for purposes of calculating the 2025 pay ratio, including all full-time and part-time employees, but excluding our Chief Executive Officer. We identified our median employee by reviewing compensation information from our payroll records and providers for 2025 using a consistently applied compensation measure, which included total taxable income, or equivalent. We then annualized compensation for employees hired during 2025.

Director Compensation

Members of our Board are compensated in accordance with Board policy as follows:

- The annual fixed sum paid to the President of the Board of Directors is \$102,000, paid monthly in arrears.
- Each Director, other than the President of the Board of Directors, receives an annual fixed sum of \$96,000, paid monthly in arrears.
- The fixed sum is intended to compensate directors for preparation for, travel to and from, and attendance at Official Meetings, as defined in the Board policy, where Basin Electric business is covered or representation is necessary.
- Directors are reimbursed for actual expenses incurred in traveling to, from, and while attending Official Meetings based on reimbursement guidelines defined in Board Policy.

Directors' Deferred Compensation Plan

Basin Electric's Board of Directors, including the Board President, are eligible to participate in the Board Deferred Compensation Plan, an unfunded and unsecured deferred compensation arrangement governed by Section 409A of the Internal Revenue Code.

For 2025, directors continued their existing deferral elections under the prior compensation structure, even though Board compensation transitioned to a fixed annual payment beginning on January 15, 2025. The Plan itself was not amended for 2025, so all elections remained in effect for the year.

Deferred amounts are credited to a notional account and adjusted for investment performance. Plan assets are held in a rabbi trust and remain subject to the claims of Basin Electric's general creditors.

Director Compensation Table

The following table sets forth the total compensation paid or earned by each of our directors for the fiscal year ended December 31, 2025. Directors are also reimbursed for expenses as described above.

Name	Total Fees Earned or Paid in Cash (\$)⁽¹⁾
Wayne Peltier	102,000
Paul Baker	96,000
Tom Wagner	96,000
Leo Brekel	96,000
Jerry Beck	96,000
Daniel Gliko, Jr.	96,000
Anthony Larson	96,000
David Meschke	96,000
Kermit Pearson	96,000
Troy Presser	96,000
Mike McQuiston ⁽²⁾	96,000

(1) Various directors have deferred a total of \$66,000 of the actual Board fee payments made in 2025.

(2) Mr. McQuiston passed away on February 17, 2026.

CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

Certain Relationships and Related Transactions

Basin Electric maintains a Code of Conduct and related policies requiring the disclosure and review of actual or potential conflicts of interest, including related-person relationships and transactions, applicable to all employees, officers, and directors, with review by management and, when appropriate, the Board.

Because Basin Electric is a cooperative, its members are also its owners, and each director, as required by our bylaws, serves as a director of the Class A Member that the director represents on the Board. Each Class A Member has a wholesale power contract with us, and we received revenue from each such Class A Member in excess of \$120,000 during fiscal year 2025.

Other than the transactions described above, we did not have any transactions during 2025, nor do we have any currently proposed transactions, in which a related person had or will have a direct or indirect material interest that exceeded \$120,000.

Director Independence

Because we are a cooperative, our members own us. Our bylaws set forth the specific requirements regarding the composition of our Board. See "[DIRECTORS, EXECUTIVE OFFICERS, AND CORPORATE GOVERNANCE—Corporate Governance](#)" for a description of these requirements. In addition to meeting the requirements set forth in our bylaws, all of our current directors satisfy the definition of director independence as prescribed by the Nasdaq Stock Market and otherwise meet all the requirements set forth in our bylaws. Although we do not have any securities listed on the Nasdaq Stock Market, we have used its independence criteria to make this determination in accordance with applicable SEC rules.

SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

Not applicable.

THE EXCHANGE OFFER

Purpose of the Exchange Offer

We completed the private offering of the Original Bonds on October 14, 2025. As part of that issuance, we entered into the Registration Rights Agreement with the initial purchasers in the private offering. Under the Registration Rights Agreement, we agreed to file a registration statement with the SEC relating to the Exchange Offer within 210 days of the settlement date of the Original Bonds. We also agreed to use our commercially reasonable efforts to (i) cause the registration statement to become effective with the SEC within 360 days of the settlement date of the Original Bonds and (ii) complete the Exchange Offer within 60 business days from the date the registration statement becomes effective. The Registration Rights Agreement provides that we will be required to pay additional interest to the holders of the Original Bonds if we fail to comply with such filing, effectiveness and exchange offer consummation requirements. We also agreed to perform other obligations under the Registration Rights Agreement. See “—Registration Rights Agreement.”

The Exchange Offer is not being made to holders of Original Bonds in any jurisdiction where the exchange would not comply with the securities or blue sky laws of such jurisdiction. A copy of the Registration Rights Agreement has been filed as an exhibit to the registration statement of which this prospectus forms a part, and it is available from us upon request. See “Where You Can Find More Information.”

Each broker-dealer that receives Exchange Bonds for its own account in exchange for Original Bonds, where such Original Bonds were acquired by such broker-dealer as a result of market-making activities or other trading activities, must acknowledge that it will deliver a prospectus in connection with any resale of such Exchange Bonds. See “[PLAN OF DISTRIBUTION](#).”

Terms of the Exchange Offer

Upon the terms and subject to the conditions described in this prospectus and in the accompanying letter of transmittal, we will accept for exchange Original Bonds that are validly tendered before 5:00 p.m., New York City time, on the expiration date and not validly withdrawn as permitted below. We will issue a like principal amount of Exchange Bonds in exchange for the principal amount of the Original Bonds tendered under the Exchange Offer. As used in this prospectus, the term “expiration date” means June 4, 2026. However, if we have extended the period of time for which the Exchange Offer is open, the term “expiration date” means the latest date to which we extend the Exchange Offer.

As of the date of this prospectus, \$700,000,000 aggregate principal amount of Original Bonds is outstanding. The Original Bonds were issued under the Indenture, as supplemented by the Forty-Second Supplemental Indenture. Our obligation to accept Original Bonds for exchange in the Exchange Offer is subject to the conditions described below under “—Conditions to the Exchange Offer.” We reserve the right to extend the period of time during which the Exchange Offer is open. We may, subject to applicable law, elect to extend the Exchange Offer period if less than 100% of the Original Bonds are tendered or if any condition to consummation of the Exchange Offer has not been satisfied as of the expiration date and it is likely that such condition will be satisfied after such date. In addition, in the event of any material change to the Exchange Offer, we will extend the period of time during which the Exchange Offer is open as necessary. In the event of such extension, and only in such event, we may delay acceptance for exchange of any Original Bonds by giving written notice of the extension to the holders of Original Bonds as described below. During any extension period, all Original Bonds previously tendered will remain subject to the Exchange Offer and may be accepted for exchange by us. Any Original Bonds not accepted for exchange will be returned to the tendering holder promptly after the expiration or termination of the Exchange Offer.

Original Bonds tendered in the Exchange Offer must be in denominations of \$2,000 and any integral multiple of \$1,000 in excess thereof.

Subject to applicable law, we reserve the right to amend or terminate the Exchange Offer, and not to accept for exchange any Original Bonds not previously accepted for exchange, upon the occurrence of any of the conditions of the Exchange Offer specified below under “—Conditions to the Exchange Offer.” We will give written notice of any extension, amendment, non-acceptance or termination to the holders of the Original Bonds as promptly as practicable. Such notice, in the case of any extension, will be issued by means of a press release or other public announcement no later than 9:00 a.m., New York City time, on the next business day after the previously scheduled expiration date.

Our acceptance of the tender of Original Bonds by a tendering holder will form a binding agreement upon the terms and subject to the conditions provided in this prospectus and the accompanying letter of transmittal.

Absence of Dissenters’ Rights of Appraisal

Holders of Original Bonds do not have any dissenters’ rights of appraisal in connection with the Exchange Offer.

Procedures for Tendering

Except as described below, a holder tendering Original Bonds must, prior to 5:00 p.m., New York City time, on the expiration date:

- transmit a properly completed and duly executed letter of transmittal, including all other documents required by the letter of transmittal, to the Exchange Agent, at the address listed below under the heading “—Exchange Agent”; or
- if Original Bonds are tendered in accordance with the book-entry procedures described below, the tendering holder must transmit an agent’s message (described below) to the Exchange Agent.

Transmittal will be deemed made only when actually received or confirmed by the Exchange Agent.

In addition, the Exchange Agent must receive, before 5:00 p.m., New York City time, on the expiration date:

- certificates for the Original Bonds; or
- confirmation of book-entry transfer of the Original Bonds into the Exchange Agent’s account at DTC, the book-entry transfer facility.

The term “agent’s message” means a computer-generated message, transmitted by DTC to, and received by, the Exchange Agent and forming a part of a book-entry confirmation, which states that DTC has received an express acknowledgment from the tendering participant that such participant has received and agrees to be bound by, and makes the representations and warranties contained in, the letter of transmittal and that we may enforce the letter of transmittal against such participant.

The method of delivery of Original Bonds, letters of transmittal and all other required documents is at your election and risk. If delivery is by mail, we recommend that you use registered mail, properly insured, with return receipt requested. In all cases, you should allow sufficient time to assure timely delivery. You should not send letters of transmittal or Original Bonds to anyone other than the Exchange Agent.

If you are a beneficial owner whose Original Bonds are registered in the name of a broker, dealer, commercial bank, trust company or other nominee, and wish to tender, you should promptly instruct the registered holder to tender on your behalf. Any registered holder that is a participant in DTC’s book-entry transfer facility system may make book-entry delivery of the Original Bonds by causing DTC to transfer the Original Bonds into the Exchange Agent’s account.

Signatures on a letter of transmittal or a notice of withdrawal must be guaranteed unless the Original Bonds surrendered for exchange are tendered:

- by a registered holder of the Original Bonds that has not completed the box entitled “Special Issuance Instructions” or “Special Delivery Instructions” on the letter of transmittal; or
- for the account of an “eligible institution.”

If signatures on a letter of transmittal or a notice of withdrawal are required to be guaranteed, the guarantees must be by an “eligible institution.” An “eligible institution” is a financial institution, including most banks, savings and loan associations and brokerage houses, that is a participant in the Securities Transfer Agents Medallion Program, the New York Stock Exchange Medallion Signature Program or the Stock Exchanges Medallion Program.

We will reasonably determine all questions as to the validity, form and eligibility of Original Bonds tendered for exchange and all questions concerning the timing of receipts and acceptance of tenders. These determinations will be final and binding.

We reserve the right to reject any particular Original Bond not validly tendered, or any acceptance that might, in our judgment, be unlawful. We also reserve the right to waive any defects or irregularities with respect to the form of, or procedures applicable to, the tender of any particular Original Bond before the expiration date. Unless waived, any defects or irregularities in connection with tenders of Original Bonds must be cured before the expiration date of the Exchange Offer. Neither we, the Exchange Agent nor the Trustee, nor any other person, will be under any duty to give notification of any defect or irregularity in any tender of Original Bonds. Neither we, the Exchange Agent nor the Trustee, nor any other person, will incur any liability for failing to give notification of any defect or irregularity.

If the letter of transmittal is signed by a person other than the registered holder of Original Bonds, the letter of transmittal must be accompanied by a physical certificate representing the Original Bonds endorsed by the registered holder or written instrument of transfer or exchange in satisfactory form, duly executed by the registered holder, in either case with the signature guaranteed by an eligible institution. In addition, in either case, the original endorsement or the instrument of transfer must be signed exactly as the name of any registered holder appears on the Original Bonds.

If the letter of transmittal or any Original Bonds or powers of attorney are signed by trustees, executors, administrators, guardians, attorneys-in-fact, officers of corporations or others acting in a fiduciary or representative capacity, these persons should so indicate when signing. Unless waived by us, proper evidence satisfactory to us of their authority to so act must be submitted.

By signing or agreeing to be bound by the letter of transmittal, each tendering holder of Original Bonds will represent, among other things, that:

- it is not an affiliate of ours or, if it is an affiliate of ours, it will comply with the registration and prospectus delivery requirements of the Securities Act to the extent applicable in connection with the resale of the Exchange Bonds;
- the Exchange Bonds to be received by it will be acquired in the ordinary course of its business;
- it is not engaged in and does not intend to engage in, and has no arrangement or understanding with any person to participate in, a distribution, within the meaning of the Securities Act, of the Exchange Bonds;
- it is not a broker-dealer that purchased any of the Original Bonds from us or any of our affiliates for resale pursuant to Rule 144A or any other available exemption under the Securities Act; and
- if such holder is a broker-dealer that will receive Exchange Bonds for its own account in exchange for Original Bonds that were acquired as a result of market-making activities or other

trading activities, that it will deliver a prospectus (or to the extent permitted by law, make available a prospectus to purchasers) in connection with any resale of such Exchange Bonds. See “[PLAN OF DISTRIBUTION](#).”

Acceptance of Original Bonds for Exchange; Delivery of Exchange Bonds

Upon satisfaction of all of the conditions to the Exchange Offer, we will accept, promptly after the expiration date, all Original Bonds validly tendered. We will issue the Exchange Bonds promptly after the expiration of the Exchange Offer and acceptance of the Original Bonds. See “—Conditions to the Exchange Offer” below. For purposes of the Exchange Offer, we will be deemed to have accepted validly tendered Original Bonds for exchange when, as and if we have given written notice of such acceptance to the Exchange Agent.

For each Original Bond accepted for exchange, the holder of the Original Bond will receive an Exchange Bond having a principal amount equal to that of the surrendered Original Bond. The Exchange Bonds will bear interest from the last date on which interest was paid on the Original Bonds. Original Bonds accepted for exchange will cease to accrue interest from and after the date of completion of the Exchange Offer. Holders of Original Bonds whose Original Bonds are accepted for exchange will not receive any payment for accrued interest on the Original Bonds otherwise payable on any interest payment date, the record date for which occurs on or after completion of the Exchange Offer and will be deemed to have waived their rights to receive such accrued interest on the Original Bonds.

In all cases, issuance of Exchange Bonds for Original Bonds will be made only after timely receipt by the Exchange Agent of:

- certificates for the Original Bonds or a book-entry confirmation of the deposit of the Original Bonds into the Exchange Agent’s account at the book-entry transfer facility;
- a properly completed and duly executed letter of transmittal or a transmitted agent’s message; and
- all other required documents.

Unaccepted or non-exchanged Original Bonds will be returned without expense to the tendering holder of the Original Bonds promptly after the expiration of the Exchange Offer. In the case of Original Bonds tendered by book-entry transfer in accordance with the book-entry procedures described below, the non-exchanged Original Bonds will be returned or recredited promptly after the expiration of the Exchange Offer.

Book-Entry Transfer

The Exchange Agent will make a request to establish an account for the Original Bonds at DTC for purposes of the Exchange Offer within two business days after the date of this prospectus. Any financial institution that is a participant in DTC’s systems and is tendering Original Bonds must make book-entry delivery of the Original Bonds by causing DTC to transfer those Original Bonds into the Exchange Agent’s account at DTC in accordance with DTC’s procedures for transfer, including its Automated Tender Offer Program, or ATOP, procedures. The participant should transmit its acceptance to DTC prior to 5:00 p.m., New York City time, on the expiration date. DTC will verify this acceptance, execute a book-entry transfer of the tendered Original Bonds into the Exchange Agent’s account at DTC and then send to the Exchange Agent confirmation of this book-entry transfer, which confirmation must be received prior to 5:00 p.m., New York City time, on the expiration date. The confirmation of this book-entry transfer will include an agent’s message confirming that DTC has received an express acknowledgment from the participant that the participant has received and agrees to be bound by the letter of transmittal and that we may enforce the letter of transmittal against the participant. Delivery of Exchange Bonds issued in the Exchange Offer may be effected through book-entry transfer at DTC. However, the letter of transmittal (or an agent’s message in lieu thereof), with any required signature guarantees and any other required

documents, must be transmitted to, and received by, the Exchange Agent at the address listed below under “—Exchange Agent” (or its account at DTC with respect to an agent’s message) prior to 5:00 p.m., New York City time, on the expiration date.

Withdrawal Rights

For a withdrawal to be effective, the Exchange Agent must receive a written notice of withdrawal at the address indicated below under “—Exchange Agent” before 5:00 p.m., New York City time, on the expiration date. Any notice of withdrawal must:

- specify the name of the person, referred to as the depositor, having tendered the Original Bonds to be withdrawn;
- identify the Original Bonds to be withdrawn, certificate number or numbers, if applicable, and principal amount of the Original Bonds;
- in the case of Original Bonds tendered by book-entry transfer, specify the number of the account at the book-entry transfer facility from which the Original Bonds were tendered and specify the name and number of the account at the book-entry transfer facility to be credited with the withdrawn Original Bonds and otherwise comply with the procedures of such facility;
- contain a statement that the holder is withdrawing their election to have the Original Bonds exchanged;
- be signed by the holder in the same manner as the original signature on the letter of transmittal by which the Original Bonds were tendered, including any required signature guarantees, or be accompanied by documents of transfer to have the Trustee with respect to the Original Bonds register the transfer of the Original Bonds in the name of the person withdrawing the tender, together with satisfactory evidence of payment of applicable transfer taxes or exemption therefrom; and
- specify the name in which the Original Bonds are registered, if different from that of the depositor.

If certificates for Original Bonds have been delivered or otherwise identified to the Exchange Agent, then, prior to the release of these certificates, the withdrawing holder must also submit the serial numbers of the particular certificates to be withdrawn and a signed notice of withdrawal with signatures guaranteed by an eligible institution unless this holder is an eligible institution. We will determine all questions as to the validity, form and eligibility, including time of receipt, of notices of withdrawal. Validly withdrawn Original Bonds may be re-tendered by following the procedures described under “—Procedures for Tendering” above at any time before 5:00 p.m., New York City time, on the expiration date.

Conditions to the Exchange Offer

Notwithstanding any other provision of this prospectus, with respect to the Exchange Offer, we will not be obligated to (i) accept for exchange any validly tendered Original Bonds or (ii) issue any Exchange Bonds in exchange for validly tendered Original Bonds or complete the Exchange Offer, if at or prior to the expiration date:

- (1) there is threatened, instituted or pending any action or proceeding before, or any injunction, order or decree issued by, any court or governmental agency or other governmental regulatory or administrative agency or commission that might materially impair our ability to proceed with the Exchange Offer; or
- (2) the Exchange Offer or the making of any exchange by a holder of Original Bonds would violate applicable law or any applicable interpretation of the SEC staff.

In addition, we will not accept for exchange any Original Bonds tendered, and no Exchange Bonds will be issued in exchange for any Original Bonds, if any stop order is threatened by the SEC or in effect relating to the registration statement of which this prospectus constitutes a part or the qualification of the Indenture under the Trust Indenture Act of 1939, as amended. We are required to use our commercially reasonable efforts to obtain the withdrawal of any stop order suspending the effectiveness of a registration statement at the earliest possible time.

The Exchange Offer is not conditioned upon any minimum amount of Original Bonds being tendered.

Exchange Agent

We have appointed U.S. Bank Trust Company, National Association as the Exchange Agent for the Exchange Offer. You should direct all executed letters of transmittal to the Exchange Agent at the address indicated below. You should direct questions and requests for assistance, and requests for additional copies of this prospectus or of the letter of transmittal to the Exchange Agent addressed as follows:

Deliver To:

<i>By Mail:</i>	<i>By Hand or Overnight Courier:</i>	<i>For Information or Confirmation by Email or Telephone:</i>
U.S. Bank Trust Company, National Association Corporate Trust Services P.O. Box 64111 St. Paul, MN 55164-0111	U.S. Bank Trust Company, National Association Corporate Trust Services 60 Livingston Avenue 1st Fl – Bond Drop Window St. Paul, MN 55107	1-800-934-6802 cts.specfinance@usbank.com

All other questions should be addressed to Basin Electric Power Cooperative, 1717 East Interstate Avenue, Bismarck, North Dakota 58503-0564, Attention: Vice President & Treasurer, or by calling us at (701) 223-0441. If you deliver the letter of transmittal to an address other than any address for the Exchange Agent indicated above, then your delivery or transmission will not constitute a valid delivery of the letter of transmittal.

Fees and Expenses

We will not make any payment to brokers, dealers or others soliciting acceptances of the Exchange Offer. We have agreed to pay all expenses incident to the Exchange Offer other than commissions or concessions of any broker-dealers and will indemnify the holders of the Original Bonds and the Exchange Bonds (including any broker-dealers) against certain liabilities, including liabilities under the Securities Act. The cash expenses to be incurred in connection with the Exchange Offer, including out-of-pocket expenses for the Exchange Agent, will be paid by us.

Transfer Taxes

We will pay any transfer taxes in connection with the tender of Original Bonds in the Exchange Offer unless you instruct us to register Exchange Bonds in the name of, or request that Original Bonds not tendered or not accepted in the Exchange Offer be returned to, a person other than the tendering registered holder. In those cases, you will be responsible for the payment of any applicable transfer taxes.

Accounting Treatment

The Exchange Bonds will be recorded at the same carrying value as the Original Bonds as reflected in our accounting records on the date of the exchange. Accordingly, we will not recognize any gain or loss for accounting purposes upon the completion of the Exchange Offer. The expenses of the Exchange Offer will be amortized over the term of the Exchange Bonds.

Consequences of Exchanging or Failing to Exchange the Original Bonds

Holders of Original Bonds that do not exchange their Original Bonds for Exchange Bonds in the Exchange Offer will remain subject to the restrictions on transfer of such Original Bonds as set forth in the legend printed on the global certificates representing the Original Bonds as a consequence of the issuance of the Original Bonds pursuant to exemptions from, or in transactions not subject to, the registration requirements of the Securities Act and applicable state securities laws. In general, you may not offer or sell the Original Bonds unless they are registered under the Securities Act, transferred pursuant to an exemption from registration under the Securities Act and applicable state securities laws or transferred in a transaction not subject to the Securities Act and applicable state securities laws. Except as required by the Registration Rights Agreement, we do not intend to register resales of the Original Bonds under the Securities Act.

Under existing interpretations of the Securities Act by the SEC staff contained in several no-action letters to third parties, and subject to the immediately following sentence, we believe the Exchange Bonds would generally be freely transferable by holders other than our affiliates after the Exchange Offer without further registration under the Securities Act, subject to certain representations required to be made by each holder of Exchange Bonds, as set forth below. However, any holder of Original Bonds that is one of our “affiliates” (as defined in Rule 405 under the Securities Act) that does not comply with the registration and prospectus delivery requirements of the Securities Act to the extent applicable in connection with the resale of the Exchange Bonds or that intends to participate in the Exchange Offer for the purpose of distributing the Exchange Bonds, or any broker-dealer that purchased any of the Original Bonds from us or any of our affiliates for resale pursuant to Rule 144A or any other available exemption under the Securities Act:

- will not be able to rely on the interpretations of the SEC staff;
- will not be able to tender its Original Bonds in the Exchange Offer; and
- must comply with the registration and prospectus delivery requirements of the Securities Act in connection with any sale or transfer of Original Bonds unless such sale or transfer is made pursuant to an exemption from such requirements. See “[PLAN OF DISTRIBUTION](#).”

We do not intend to seek our own interpretation from the SEC staff regarding the Exchange Offer, and there can be no assurance that the SEC staff would make a similar determination with respect to the Exchange Bonds as it has in other interpretations to other parties, although we have no reason to believe otherwise.

Registration Rights

In connection with the closing of the private offering of the Original Bonds on October 14, 2025, we entered into the Registration Rights Agreement with the representatives of the initial purchasers of the Original Bonds. The following description of the Registration Rights Agreement is a summary of certain provisions of the Registration Rights Agreement and is qualified in its entirety by reference to all the provisions of such document. A copy of the form of the Registration Rights Agreement is incorporated by reference as an exhibit to the registration statement of which this prospectus is a part. See “Where You Can Find More Information.”

Pursuant to the Registration Rights Agreement, we agreed, for the benefit of the holders of the Original Bonds, at our cost, to use commercially reasonable efforts to:

- file, not later than 210 days after the settlement date for the Original Bonds, a registration statement (the “Exchange Offer Registration Statement”) with respect to a registered offer to exchange the Original Bonds for the Exchange Bonds, a new series of bonds having terms substantially identical to the Original Bonds and entitled to the benefits of the Indenture, except that the Exchange Bonds will be registered under the Securities Act and will not have (i) any

transfer restrictions under the Securities Act or (ii) registration rights or additional interest provisions under the Registration Rights Agreement;

- cause the Exchange Offer Registration Statement to become effective within 360 days after the settlement date for the Original Bonds; and
- complete the Exchange Offer within 60 business days from the date the Exchange Offer Registration Statement becomes effective.

This prospectus is a part of a registration statement we have filed with the SEC. Promptly after this registration statement has been declared effective, we will commence the Exchange Offer.

If:

- we determine that we are not permitted to effect the Exchange Offer because it would violate any applicable law or applicable interpretations of the staff of the SEC;
- for any other reason, the Exchange Offer Registration Statement is not effective within 360 days of the settlement date for the Original Bonds or the Exchange Offer is not completed within 60 business days after the date the Exchange Offer Registration Statement becomes effective; or
- we receive a written request, not later than 20 days after the completion of the Exchange Offer, from any holder of Original Bonds that are or were ineligible to be exchanged in the Exchange Offer (the date of any of the events in this and the prior two bullet points, a “Alternative Registration Event Date”),

then we will, at our cost, use commercially reasonable efforts to:

- file with the SEC, no later than 30 business days after such Alternative Registration Event Date (but no earlier than 210 days after the settlement date for the Original Bonds), an alternative registration statement (the “Alternative Registration Statement”) providing for the resale of all the Original Bonds by the holders thereof and to have such Alternative Registration Statement become effective; and
- keep the Alternative Registration Statement effective until the earlier of the first anniversary of the effectiveness of the Alternative Registration Statement or such time as there are no longer any such Original Bonds outstanding.

Upon notice to the relevant holders, we may suspend the use or the effectiveness of the Alternative Registration Statement, or extend the time period in which it is required to file the Alternative Registration Statement, for up to 30 consecutive days and up to 60 days in the aggregate, in each case in any 12-month period (a “Suspension Period”) if we determine that there is a valid business purpose for suspension of the Alternative Registration Statement. We are required to promptly notify the relevant holders when the Alternative Registration Statement may once again be used or is effective.

A holder that sells Original Bonds pursuant to the Alternative Registration Statement generally will be required to be named as a selling security holder in the related prospectus and to deliver a prospectus to purchasers, will be subject to certain of the civil liability provisions under the Securities Act in connection with such sales and will be bound by the provisions of the Registration Rights Agreement that are applicable to such holder, including certain indemnification obligations. In addition, a holder of Original Bonds will be required to deliver information to be used in connection with the Alternative Registration Statement in order to have that holder’s Original Bonds included in the Alternative Registration Statement and to benefit from the provisions set forth in the following paragraph.

If:

- the Exchange Offer Registration Statement is not filed with the SEC on or prior to the 210th day after the settlement date for the Original Bonds;
- the Exchange Offer Registration Statement is not declared effective by the SEC or does not otherwise become effective on or prior to the 360th day after the settlement date for the Original Bonds;
- the Exchange Offer is not completed within 60 business days after the initial effective date of the Exchange Offer Registration Statement;
- the Alternative Registration Statement, if applicable, is not filed with the SEC on or prior to the later of the 30th business day after the Alternative Registration Event Date or the 210th day after the settlement date for the Original Bonds;
- the Alternative Registration Statement, if applicable, is not declared effective by the SEC or does not otherwise become effective on or prior to the later of the 150th day after the Alternative Registration Event Date or the 360th day after the settlement date for the Original Bonds; or
- the Exchange Offer Registration Statement or Alternative Registration Statement is filed and declared effective but thereafter is either withdrawn by us or becomes subject to an effective stop order issued pursuant to the Securities Act suspending the effectiveness of such registration statement (except as specifically permitted, including with respect to any Alternative Registration Statement, during any applicable Suspension Period) without being succeeded within 30 days from the date such registration statement was suspended by an additional registration statement filed and declared effective (each such event referred to in this bullet point and any of the previous five bullet points, a “Registration Default”),

then, we will pay additional interest to the holders of the Registrable Securities (as defined in the Registration Rights Agreement) affected thereby, and that additional interest will accrue on the principal amount of the Registrable Securities affected thereby, in addition to the stated interest on the Registrable Securities, from the date on which any Registration Default has occurred to the date on which all such Registration Defaults have been cured. Additional interest will accrue at a rate of 0.25% per annum for the first 90 days following a Registration Default and at a rate per annum of 0.50% thereafter (“Special Interest”). Special Interest will accrue and be payable only with respect to a single Registration Default at any given time, notwithstanding the fact that multiple Registration Defaults may exist at such time. Immediately upon the cure of all Registration Defaults, the accrual of Special Interest will cease and the interest rate on the Bonds will revert to the original rate.

The Registration Rights Agreement provides that a holder of Original Bonds is deemed to have agreed to be bound by the provisions of the Registration Rights Agreement whether or not the holder has signed the Registration Rights Agreement.

DESCRIPTION OF THE EXCHANGE BONDS

General

The terms of the Exchange Bonds to be issued in the Exchange Offer are substantially identical to the Original Bonds, except that the Exchange Bonds will be registered under the Securities Act and the transfer restrictions, registration rights and additional interest provisions applicable to the Original Bonds do not apply to the Exchange Bonds. The Exchange Bonds will be issued pursuant to and secured under the Indenture, as supplemented by the Forty-Second Supplemental Indenture. The security for the Exchange Bonds is described below under "[SUMMARY OF THE INDENTURE](#)." The following summary of certain terms and provisions of the Exchange Bonds does not purport to be complete and is subject to, and is qualified in its entirety by reference to, the terms and provisions of the Exchange Bonds, the Indenture and the Forty-Second Supplemental Indenture, including the definitions therein, copies of which are incorporated by reference as exhibits to the registration statement of which this prospectus forms a part. See "[WHERE YOU CAN FIND MORE INFORMATION](#)." We urge you to read the Indenture and the Forty-Second Supplemental Indenture, including the form of Bond included therein, because they, and not this description, define your rights as a holder of the Exchange Bonds. References to "we," "us," "our" and the "Company" in this section refer to Basin Electric Power Cooperative only and not to any of our subsidiaries.

The Exchange Bonds will mature on October 15, 2055. We will pay interest on the Exchange Bonds at the annual rate of 5.850% (on the basis of a 360-day year of twelve 30-day months). Interest on the Exchange Bonds will accrue from the last date on which interest was paid on the Original Bonds, and is payable semi-annually in arrears on April 15 and October 15 of each year. On each interest payment date, we will pay interest to the person in whose name the Exchange Bonds are registered at 5:00 p.m., New York City time, on the regular record date for that interest payment, which is the 1st day (whether or not a business day) of the calendar month of such interest payment date. If interest on the Exchange Bonds is not punctually paid or duly provided for, instead of paying such interest to the registered holders as of the regular record date, we will propose a new payment date and such interest will be paid to the registered holders of the Exchange Bonds as of a special record date, which will be no more than 15 days and no less than 10 days prior to the proposed payment date. If any interest payment date, redemption date or the maturity date of the Exchange Bonds falls on a day that is not a business day, the payment due on that interest payment date, redemption date or the maturity date will be made on the next business day, and without any interest or other payment in respect of such delay. Principal of, and premium (if any) and interest on, the Exchange Bonds will be payable, and the transfer of interests in the Exchange Bonds will be effected, through the facilities of DTC, as described below under the caption "[BOOK-ENTRY SETTLEMENT AND CLEARANCE](#)." The Exchange Bonds will be issued in minimum denominations of \$2,000 and integral multiples of \$1,000 in excess thereof.

The Exchange Bonds will be registered in the name of Cede & Co., as nominee of DTC, pursuant to DTC's book-entry system. Purchases of beneficial interests in the Exchange Bonds will be made in book-entry form, without certificates. If at any time the book-entry system is discontinued for the Exchange Bonds, the Exchange Bonds will be exchangeable for other fully registered certificated Exchange Bonds of like tenor and of an equal aggregate principal amount, in authorized denominations. See "[BOOK-ENTRY SETTLEMENT AND CLEARANCE](#)." The Trustee may impose a charge sufficient to reimburse us or the Trustee for any tax, fee or other governmental charge required to be paid with respect to such exchange or any transfer of an Exchange Bond. The cost to us or the Trustee, if any, of preparing each new Exchange Bond issued upon such exchange or transfer, and any other expenses incurred by us or the Trustee in connection therewith, will be paid by the person requesting such exchange or transfer.

Optional Redemption

At any time or from time to time before April 15, 2055 (the date that is six months prior to the maturity date of the Exchange Bonds) (the "Par Call Date"), we may redeem the Exchange Bonds at our option, in

whole or in part, at a “make whole” redemption price (expressed as a percentage of principal amount and rounded to three decimal places) equal to the greater of:

- (a) the sum of the present values of the remaining scheduled payments of principal and interest on the Exchange Bonds to be redeemed discounted to the redemption date (assuming the Exchange Bonds to be redeemed matured on the Par Call Date) on a semi-annual basis (assuming a 360-day year consisting of twelve 30-day months) at the Treasury Rate (as defined below) plus 20 basis points less (b) interest accrued on the Bonds to be redeemed to the date of redemption; and
- 100% of the principal amount of the Bonds to be redeemed;

plus, in either case, accrued and unpaid interest thereon, if any, to, but excluding, the redemption date.

At any time or from time to time on or after the Par Call Date, we may redeem the Exchange Bonds at our option, in whole or in part, at a redemption price equal to 100% of the principal amount of the Exchange Bonds being redeemed, plus accrued and unpaid interest thereon, if any, to, but excluding, the redemption date.

“*Treasury Rate*” means, with respect to any redemption date, the yield determined by us in accordance with the following two paragraphs.

The Treasury Rate shall be determined by us after 4:15 p.m., New York City time (or after such time as yields on U.S. government securities are posted daily by the Board of Governors of the Federal Reserve System), on the third business day preceding the redemption date based upon the yield or yields for the most recent day that appear after such time on such day in the most recent statistical release published by the Board of Governors of the Federal Reserve System designated as “Selected Interest Rates (Daily) - H.15” (or any successor designation or publication) (“H.15”) under the caption “U.S. government securities–Treasury constant maturities–Nominal” (or any successor caption or heading) (“H.15 TCM”). In determining the Treasury Rate, we shall select, as applicable: (1) the yield for the Treasury constant maturity on H.15 exactly equal to the period from the redemption date to the Par Call Date (the “Remaining Life”); or (2) if there is no such Treasury constant maturity on H.15 exactly equal to the Remaining Life, the two yields – one yield corresponding to the Treasury constant maturity on H.15 immediately shorter than and one yield corresponding to the Treasury constant maturity on H.15 immediately longer than the Remaining Life – and shall interpolate to the Par Call Date on a straight-line basis (using the actual number of days) using such yields and rounding the result to three decimal places; or (3) if there is no such Treasury constant maturity on H.15 shorter than or longer than the Remaining Life, the yield for the single Treasury constant maturity on H.15 closest to the Remaining Life. For purposes of this paragraph, the applicable Treasury constant maturity or maturities on H.15 shall be deemed to have a maturity date equal to the relevant number of months or years, as applicable, of such Treasury constant maturity from the redemption date.

If on the third business day preceding the redemption date H.15 TCM is no longer published, we shall calculate the Treasury Rate based on the rate per annum equal to the semi-annual equivalent yield to maturity at 11:00 a.m., New York City time, on the second business day preceding such redemption date of the United States Treasury security maturing on, or with a maturity that is closest to, the Par Call Date, as applicable. If there is no United States Treasury security maturing on the Par Call Date but there are two or more United States Treasury securities with a maturity date equally distant from the Par Call Date, one with a maturity date preceding the Par Call Date and one with a maturity date following the Par Call Date, we shall select the United States Treasury security with a maturity date preceding the Par Call Date. If there are two or more United States Treasury securities maturing on the Par Call Date or two or more United States Treasury securities meeting the criteria of the preceding sentence, we shall select from among these two or more United States Treasury securities the United States Treasury security that is trading closest to par based upon the average of the bid and asked prices for such United States Treasury securities at 11:00 a.m., New York City time. In determining the Treasury Rate in accordance

with the terms of this paragraph, the semi-annual yield to maturity of the applicable United States Treasury security shall be based upon the average of the bid and asked prices (expressed as a percentage of principal amount) at 11:00 a.m., New York City time, of such United States Treasury security, and rounded to three decimal places.

Our actions and determinations in determining the redemption price shall be conclusive and binding for all purposes, absent manifest error.

Notice of any redemption will be transmitted at least 30 days but not more than 60 days before the redemption date to each holder of the Exchange Bonds to be redeemed. Unless we default in payment of the redemption price, on or after the redemption date, interest will cease to accrue on the Exchange Bonds called for redemption.

If less than all of the Exchange Bonds are to be redeemed, the Trustee will select pro rata or by lot or in such other manner as the Trustee shall deem fair and appropriate the Exchange Bonds to be redeemed, provided that as long as the Exchange Bonds are registered in the name of Cede & Co., as nominee of DTC, the Exchange Bonds to be redeemed may be selected by DTC in accordance with applicable DTC procedures. The Trustee may select for redemption Exchange Bonds and portions of Exchange Bonds in amounts of \$2,000 and integral multiples of \$1,000 in excess thereof (provided that the unredeemed portion of such Exchange Bonds redeemed in part will not be less than \$2,000) and shall thereafter promptly notify us in writing of the numbers of Exchange Bonds to be redeemed, in whole or in part.

The Exchange Bonds will not be subject to repayment at the option of the holder at any time prior to maturity.

BOOK-ENTRY SETTLEMENT AND CLEARANCE

The information in this section concerning the operations and procedures of DTC, Clearstream and Euroclear is provided solely as a matter of convenience. These operations and procedures are solely within the control of these settlement systems and are subject to change by them from time to time. Neither we, the Trustee, the Exchange Agent nor any paying agent takes any responsibility for these operations or procedures, and investors are urged to contact the relevant system or its participants directly to discuss these matters.

General

The Exchange Bonds will be issued in the form of several registered bonds in global form without interest coupons (the “Global Bonds”) registered in the name of Cede & Co., as nominee of DTC (or such other name as may be requested by an authorized representative of DTC), and deposited with the Trustee as custodian for DTC for the accounts of its participants, including Clearstream Banking S.A. (“Clearstream”), and Euroclear Bank, S.A./N.V. (“Euroclear”).

Ownership of beneficial interests in the Global Bonds (“Book-Entry Interests”) will be limited to persons that have accounts with DTC, or persons that may hold interests through such participants. DTC holds interest in the Global Bonds on behalf of its participants through customers’ securities accounts in their respective names on the books of their respective depositaries. Except under the limited circumstances described below, owners of beneficial interests in the Global Bonds are not entitled to receive physical delivery of certificated bonds.

Book-Entry Interests will be shown on, and transfers thereof will be effected only through, records maintained in book-entry form by DTC and its participants. The Book-Entry Interests will not be held in definitive form. Instead, DTC will credit on its respective book-entry registration and transfer systems a participant’s account with the interest beneficially owned by such participant. The laws of some jurisdictions, including certain states of the U.S., may require that certain purchasers of securities take physical delivery of such securities in definitive form. The foregoing limitations may impair your ability to own, transfer or pledge Book-Entry Interests. In addition, while the Exchange Bonds are in global form, holders of Book-Entry Interests are not considered the owners or “holders” of Exchange Bonds for any purpose. Only the registered holder of an Exchange Bond will be treated as the owner of such Exchange Bond.

So long as the Exchange Bonds are held in global form, DTC (or its nominees) will be considered the sole holders of Global Bonds for all purposes under the Indenture governing the Exchange Bonds. Accordingly, participants in DTC must rely on the procedures of DTC and indirect participants must rely on the procedures of DTC and the participants through which they own Book-Entry Interests, to transfer their interests or to exercise any rights of holders under the Indenture.

Neither we nor the Trustee has any responsibility or liability for any aspect of the records relating to the Book-Entry Interests.

Redemption of the Global Bonds

In the event any Global Bond (or any portion thereof) is redeemed, DTC (or its nominees) will redeem an equal amount of the Book-Entry Interests in such Global Bond from the amount received by it in respect of the redemption of such Global Bond. The redemption price payable in connection with the redemption of such Book-Entry Interests will be equal to the amount received by DTC in connection with the redemption of such Global Bond (or any portion thereof). We understand that, under existing practices of DTC, if fewer than all of the Exchange Bonds are to be redeemed at any time, DTC will credit its participants’ accounts on a proportionate basis (with adjustments to prevent fractions) or by lot or on such other basis as they deem fair and appropriate; provided, however, that no Book-Entry Interest of \$2,000 principal amount or less may be redeemed in part.

Payments on Global Bonds

We will make payments of any amounts owing in respect of the Global Bonds (including principal, premium, if any, and interest) to DTC or its nominee, which will distribute such payments to participants in accordance with its procedures. We will make payments of all such amounts without deduction or withholding for or on account of any present or future taxes, duties, assessments or governmental charges of whatever nature except as may be required by law. We expect that standing customer instructions and customary practices will govern payments by participants to owners of Book-Entry Interests held through such participants.

Under the terms of the Indenture, we and the Trustee will treat the registered holders of the Global Bonds (i.e., DTC (or its nominees)) as the owners thereof for the purpose of receiving payments and for all other purposes. Consequently, neither we nor the Trustee, nor any of our or their respective agents, has or will have any responsibility or liability for:

- any aspect of the records of DTC or any participant or indirect participant relating to payments made on account of a Book-Entry Interest or for maintaining, supervising or reviewing the records of DTC, or any participant or indirect participant relating to or payments made on account of a Book-Entry Interest; or
- DTC or any participant or indirect participant.

Payments by participants to owners of Book-Entry Interests held through participants are the responsibility of such participants.

Currency of Payment for the Global Bonds

Except as may otherwise be agreed between DTC and any holder, the principal of, premium, if any, and interest on, and all other amounts payable in respect of, the Global Bonds will be paid to holders of interests in such Global Bonds through DTC in U.S. dollars.

Payments will be subject in all cases to any fiscal or other laws and regulations (including any regulations of the applicable clearing system) applicable thereto. None of us, the Trustee, or any of our or their respective agents will be liable to any holder of a Global Bond or any other person for any commissions, costs, losses or expenses in relation to or resulting from any currency conversion or rounding effected in connection with any such payment.

Action by Owners of Book-Entry Interests

DTC has advised us that it will take any action permitted to be taken by a holder of Exchange Bonds (including the presentation of Exchange Bonds for exchange as described below) only at the direction of one or more participants to whose account the Book-Entry Interests in the Global Bonds are credited and only in respect of such portion of the aggregate principal amount of Exchange Bonds as to which such participant or participants has or have given such direction. DTC will not exercise any discretion in the granting of consents, waivers or the taking of any other action in respect of the Global Bonds. However, if there is an event of default under the Exchange Bonds, DTC reserves the right to exchange the Global Bonds for definitive registered bonds in certificated form (the “Definitive Registered Bonds”), and to distribute Definitive Registered Bonds to its participants.

Transfers

Transfers of beneficial interests in the Global Bonds will be subject to the applicable rules and procedures of DTC and its direct or indirect participants, which rules and procedures may change from time to time.

Definitive Registered Bonds

Under the terms of the Indenture, owners of Book-Entry Interests will receive Definitive Registered Bonds:

- if DTC notifies us that it is unwilling or unable to continue as depository for the Global Bonds, or DTC ceases to be a clearing agency registered under the Exchange Act and, in either case, a qualified successor depository is not appointed by us within 120 days; or
- if an event of default under the Indenture occurred or is continuing and the owner of a Book-Entry Interest requests such exchange in writing delivered through DTC.

In the case of the issuance of Definitive Registered Bonds, the holder of a Definitive Registered Bond may transfer such Definitive Registered Bond by surrendering it to the registrar. In the event of a partial transfer or a partial redemption of a holding of Definitive Registered Bonds represented by one Definitive Registered Bond, a Definitive Registered Bond shall be issued to the transferee in respect of the part transferred, and a new Definitive Registered Bond in respect of the balance of the holding not transferred or redeemed shall be issued to the transferor or the holder, as applicable; provided that no Definitive Registered Bond in a denomination less than \$2,000 shall be issued. We will bear the cost of preparing, printing, packaging and delivering the Definitive Registered Bonds.

We will not be required to register the transfer or exchange of Definitive Registered Bonds for a period of 15 calendar days preceding (a) the record date for any payment of interest on the Exchange Bonds, (b) any date fixed for redemption of the Exchange Bonds or (c) the date fixed for selection of the Exchange Bonds to be redeemed in part. Also, we are not required to register the transfer or exchange of any Exchange Bonds selected for redemption. In the event of the transfer of any Definitive Registered Bond, the Trustee may require a holder, among other things, to furnish appropriate endorsements and transfer documents as described in the Indenture. We may require a holder to pay any taxes and fees required by law and permitted by the Indenture and the Exchange Bonds.

If Definitive Registered Bonds are issued and a holder thereof claims that such Definitive Registered Bonds have been lost, destroyed or wrongfully taken or if such Definitive Registered Bonds are mutilated and are surrendered to the registrar or at the office of the Trustee, we will issue and the Trustee will authenticate a replacement Definitive Registered Bond if the Trustee's and our requirements are met. The Trustee or we may require a holder requesting replacement of a Definitive Registered Bond to furnish an indemnity bond sufficient in the judgment of both the Trustee and us to protect us, the Trustee or the paying agent appointed pursuant to the Indenture from any loss which any of them may suffer if a Definitive Registered Bond is replaced. We may charge for our expenses in replacing a Definitive Registered Bond.

In case any such mutilated, destroyed, lost or stolen Definitive Registered Bond has become or is about to become due and payable, or is about to be redeemed or purchased by us pursuant to the provisions of the Indenture, we in our discretion may, instead of issuing a new Definitive Registered Bond, pay, redeem or purchase such Definitive Registered Bond, as the case may be.

Definitive Registered Bonds may be transferred and exchanged for Book-Entry Interests in a Global Bond only in accordance with the Indenture.

Information Concerning DTC

DTC has advised us that it is limited-purpose trust company organized under the New York Banking Law, a "banking organization" within the meaning of the New York Banking Law, a member of the Federal Reserve System, a "clearing corporation" within the meaning of the New York Uniform Commercial Code and a "clearing agency" registered pursuant to the provisions of Section 17A of the Exchange Act. DTC holds and provides asset servicing for issues of U.S. and non-U.S. equity, corporate and municipal debt issues that participants deposit with DTC. DTC also facilitates the post-trade settlement among

participants of sales and other securities transactions in deposited securities through electronic computerized book-entry transfers and pledges between participants' accounts. This eliminates the need for physical movement of securities certificates. Participants include both U.S. and non-U.S. securities brokers and dealers, banks, trust companies, clearing corporations and certain other organizations. Access to the DTC system is also available to indirect participants such as both U.S. and non-U.S. securities brokers and dealers, banks, trust companies and clearing corporations that clear through or maintain a custodial relationship with a participant, either directly or indirectly.

Global Clearance and Settlement Under the Book-Entry System

Except for trades involving only Euroclear and Clearstream participants, Book-Entry Interests in the Global Bonds are expected to trade in DTC's Same-Day Funds Settlement System and any permitted secondary market trading activity in such Book-Entry Interests will, therefore, be required by DTC to be settled in immediately available funds. Transfers between DTC participants will be effected in accordance with DTC rules, and will be settled in same-day funds, and transfers between participants in Euroclear or Clearstream will be effected in the ordinary way in accordance with their respective rules and operating procedures.

Cross-market transfers between the DTC participants, on the one hand, and Euroclear or Clearstream participants, on the other hand, will be effected through DTC in accordance with DTC rules on behalf of Euroclear or Clearstream, as the case may be, by its respective depository; however, such cross-market transactions will require delivery of instructions to Euroclear or Clearstream, as the case may be, by the counterparty in such system in accordance with the rules and procedures and within the established deadlines of such system. Euroclear or Clearstream, as the case may be, will, if the transaction meets its settlement requirements, deliver instructions to its respective depository to take action to effect final settlement on its behalf by delivering or receiving interests in the relevant Global Bond in DTC, and making or receiving payment in accordance with normal procedures for same-day funds settlement applicable to DTC. Euroclear and Clearstream participants may not deliver instructions directly to the depositories for Euroclear or Clearstream.

Although DTC, Clearstream and Euroclear are expected to follow the foregoing procedures in order to facilitate transfers of interests in the Global Bonds among participants in DTC, Clearstream and Euroclear, they are under no obligation to perform or continue to perform such procedures, and such procedures may be discontinued at any time. Neither we, the Trustee, the Exchange Agent nor any paying agent will have any responsibility for the performance by DTC, Euroclear, or Clearstream or their respective participants or indirect participants, of their respective obligations under the rules and procedures governing their operations.

SUMMARY OF THE INDENTURE

The Exchange Bonds will be secured under the Indenture on a parity basis with other obligations issued or to be issued under the Indenture. The following is a summary of certain provisions of the Indenture. All references to the Indenture are qualified by reference to such document, a copy of which is filed as an exhibit to the registration statement of which this prospectus forms a part. See [“WHERE YOU CAN FIND MORE INFORMATION.”](#) Capitalized terms used in this section but not otherwise defined shall have the meanings set forth in the Indenture. References to “we,” “us,” “our” and the “Company” in this section refer to Basin Electric Power Cooperative only and not to any of our subsidiaries.

Security for Payment

The Exchange Bonds will be secured equally and ratably with all other Obligations issued under the Indenture by a mortgage lien on substantially all our owned tangible and certain of our intangible properties including those we acquire in the future. These assets include electric generating plants and facilities and certain of our contracts, including (i) those that relate to the ownership, operation or maintenance of electric generation, transmission or distribution facilities owned or leased by us, (ii) those entered into prior to May 5, 2015 for the purchase or sale of electric power and energy of more than one year in duration and (iii) those entered into on or after May 5, 2015, for the purchase or sale of electric power and energy between us and our Class A Members, but excluding all Excepted Property and Excludable Property (each as defined herein).

Excepted and Excludable Property

The Indenture defines Excepted Property to include, among other things:

- cash on hand or in banks or in other financial institutions (excluding certain amounts deposited or required to be deposited with the Trustee pursuant to the Indenture and amounts representing proceeds of the Trust Estate in which, and for so long as, perfection of the lien of the Indenture continues pursuant to the Uniform Commercial Code);
- contracts not specifically subject to the lien of the Indenture;
- instruments and certain securities (other than those deposited with the Trustee under the terms of the Indenture);
- allowances for emissions or similar rights and credits arising under local, state, regional, federal or international legislation or regulation or voluntary program;
- patents, patent licenses, and other patent rights, patent applications, service marks, trade names and trademarks;
- claims, choses in action and judgments;
- transportation equipment (including vehicles, vessels, airplanes and barges and all parts and supplies used in connection therewith);
- goods or inventory acquired for the purpose of resale in the ordinary course of business including electricity, personal property consumable in the operation of our business and fuel not charged to fixed plant accounts;
- office furniture, equipment and supplies and data processing, accounting and other computer equipment, software and supplies;
- leases for office purposes and other leases for a term of less than five years;

- timber (separated from the land and included in the Trust Estate), coal, ore, gas, oil and other minerals and all electric energy, gas, steam, water or other products generated, produced or purchased;
- non-assignable permits, licenses, franchises, leases, contracts and contractual and other rights;
- certain property located outside of the states of North Dakota, South Dakota, Wyoming, Colorado, Montana, Iowa and Nebraska;
- any personal property located outside the states of North Dakota, South Dakota, Wyoming, Colorado, Montana, Iowa and Nebraska in which a security interest cannot be perfected by filing a financing statement under the Uniform Commercial Code;
- our interest in other property in which a security interest cannot legally be perfected; and
- property released from the lien of the Indenture without being sold, exchanged or otherwise disposed of by us.

The Indenture defines Excludable Property as property that would otherwise constitute Property Additions but as to which we have delivered to the Trustee prior to acquiring such property a certificate stating that such property is to be excluded from the lien of the Indenture and that we would meet our rate covenant even if we do not have use of such property.

Our title to the Trust Estate and the lien of the Indenture are subject to certain Permitted Exceptions which may include, among other things, identified restrictions, exceptions, reservations, terms, conditions, agreements, leases, subleases, covenants and limitations existing on the date such property becomes subject to the lien of the Indenture as long as such matters do not materially impair the use of such property; reservations contained in United States patents; liens for non-delinquent taxes; liens for delinquent taxes which are being contested in good faith; certain liens in respect of judgments which are being contested in good faith and for which there is a stay of execution pending appeal; mechanics', materialmen's or contractors' liens arising in the ordinary course of business which are not delinquent or which are being contested in good faith; local improvement district assessments; leases (entered into after January 1, 1998 affecting properties owned by us) for a term of not more than ten years or, if for a term of more than ten years, leases which would not materially impair our use of the leased property in the conduct of our business; certain easements, rights of way, and reservations (and the land thereunder); liens for non-delinquent wages or non-delinquent or contested rent; the undivided interests of other owners, liens on such undivided interests, and rights of such owners in property owned jointly with us; the pledge of current assets (other than accounts receivable) to secure current liabilities; and liens which have been bonded for or for the payment of which a deposit had been made in the full amount of such lien. The lien of the Indenture will also be subject to the lien in favor of the Trustee to recover amounts owed to the Trustee under the Indenture.

The Indenture contains provisions subjecting all of our after-acquired property, other than Excepted Property and Excludable Property, to the lien thereof (subject to certain purchase money and pre-existing liens).

Release and Substitution of Property

So long as no event of default exists under the Indenture, we will be able to use and deal with the real and personal property (including licenses, permits, contracts and cash proceeds of the Trust Estate, other than cash deposited or required to be deposited with the Trustee) subject to the lien of the Indenture (including amending, terminating or abandoning such property or disposing of such property, free from the lien of the Indenture) to facilitate our day-to-day operations. Certain of these transactions will require that

we find that such transactions will not adversely affect in any material respect the security under the Indenture and are:

- (i) desirable in the conduct of our business and the property to be released is no longer reasonably necessary in the conduct of our business;
- (ii) made in lieu and reasonable anticipation of the taking by eminent domain or purchase of such property by a governmental entity; or
- (iii) such release is in connection with the sale and leaseback of any property.

Certain of these release transactions also would require the substitution of Bondable Additions, the deposit of cash with the Trustee (which thereafter would constitute "Trust Moneys"), the retirement or defeasance of Obligations or the deposit of Designated Qualifying Securities with the Trustee, in each case of equivalent value of the fair value of the property to be released. Trust Moneys can be withdrawn against Bondable Additions, or retirement or defeasance of Obligations or the deposit of Designated Qualifying Securities in each case of equivalent value to the fair value of the property to be released. Trust Moneys can be withdrawn against Bondable Additions, Certified Progress Payments, retired or defeased Obligations or deposited Designated Qualifying Securities, in each case of equivalent value, and can, at our option, be used for the redemption of Obligations prior to their maturity, for the payment of principal on Obligations at their maturity or for the purchase of Obligations. To the extent that any Trust Moneys consist of the proceeds of insurance upon any part of the property subject to the lien of the Indenture, such Trust Moneys can be withdrawn to reimburse us for costs to repair, rebuild or replace the destroyed or damaged property.

Certain Covenants

Rate Covenant

The Indenture requires us to establish and collect rates, rents, charges, fees and other compensation (collectively, "Rates") for the use or the sale of the output, capacity or service of our properties that produce money sufficient, together with other moneys available to us, to enable us to comply with all of our covenants under the Indenture. Subject to the approval or determination of any regulatory or judicial authority with jurisdiction over Rates, the Indenture requires us to establish and collect Rates for the use or the sale of the output, capacity or service of our properties which are reasonably expected, together with our other revenue, to yield an MFI Ratio equal to at least 1.10 for each fiscal year. The "MFI Ratio," for any period, is the ratio of Margins for Interest for such period to Interest Charges for such period. Promptly upon any material change in the circumstances which were contemplated at the time such Rates were most recently reviewed, but not less frequently than once every twelve months, we will be required to review the Rates so established and, subject to any necessary regulatory approval, promptly establish or revise such Rates as necessary to comply with the foregoing requirements, provided that in any event such Rates shall produce moneys sufficient to enable us to comply with all of our other covenants under the Indenture. A failure by us to actually achieve a 1.10 MFI Ratio will not itself constitute an event of default under the Indenture. A failure to establish Rates reasonably expected to achieve a 1.10 MFI Ratio, however, will be an event of default if such failure continues for 45 days after we receive written notice thereof from either the Trustee or the holders of 10% in principal amount of the outstanding Obligations, unless such failure results from our inability to obtain regulatory approval.

Limitation on Distributions

The Indenture prohibits us from making any distribution, payment or retirement of patronage capital to our members if, at the time thereof or after giving effect thereto;

- (i) an event of default then existed, or

- (ii) our aggregate margins and equities as of the end of the immediately preceding fiscal quarter would be less than 20% of our total long-term debt and equities at such time.

For purposes of this covenant, such determination of aggregate margins and equities and total long-term debt and equities does not include any amount on account of earnings retained by any subsidiary or affiliate of ours and any such determination of total long-term debt and equities excludes the debt of any subsidiary or affiliate.

Limitation on Liens

The Indenture obligates us to keep all of our property subject to the lien of the Indenture free and clear of other liens prior to or on a parity with the lien of the Indenture, subject to (i) Permitted Exceptions and (ii) purchase money liens or pre-existing liens on our after-acquired property not in excess of 80% (or with respect to property that is not necessary to the operations of the remaining portion of our system, 100%) of the lesser of the cost or the fair value of such property and the aggregate amount of indebtedness secured by such liens not in excess of 15% of the aggregate principal amount of all outstanding Obligations.

Reports to Holders

The Indenture provides that, when the Indenture is qualified under the Trust Indenture Act of 1939, as amended, we will file with the Trustee and the SEC and furnish holders of Obligations with all quarterly and annual financial information and other reports that we may be required to file with the SEC pursuant to Sections 13 or 15(d) of the Exchange Act or, if we are not required to file such information or reports, then such information and reports that would be required pursuant to Section 13 of the Exchange Act if we were required to file such information and reports, in each case within the time periods specified in the SEC's rules and regulations.

In addition, we have agreed that, for so long as any of the Bonds remain outstanding and are "restricted securities" within the meaning of Rule 144(a)(3) under the Securities Act, we will, during any period in which we are not subject to and in compliance with Section 13(a) or 15(d) of the Exchange Act, or do not make voluntary filings pursuant to such Sections, furnish at our expense, upon the request of any holder of a Bond, to such holder and to a prospective purchaser of such Bond designated by such holder the information required to be delivered pursuant to Rule 144A(d)(4) under the Securities Act.

Credit Enhancement

The Indenture provides that Obligations of any series may have the benefit of an insurance policy, letter of credit, surety bond, or other similar unconditional obligation to pay when due the principal and interest of the Obligations of such series (each, a "Credit Enhancement") issued by a credit enhancer (a "Credit Enhancer").

Designated Qualifying Securities

Qualifying Securities are securities, including first mortgage bonds or other debt instruments, issued by one of our subsidiaries under an indenture, mortgage or other security instrument substantially identical in substance to our Indenture, subject to certain limited exceptions (a "Qualifying Securities Indenture"). When Qualifying Securities are pledged to and held by the Trustee and have been designated by us as the basis for (i) the issuance of additional Obligations, (ii) the withdrawal of Trust Moneys or Deposited Cash or (iii) the release of part of the Trust Estate, such securities become "Designated Qualifying Securities." Our Indenture provides that a Qualifying Securities Indenture can also be an indenture or mortgage substantially identical in substance to the Indenture entered into by any person that succeeds to our interest in property constituting part of the Trust Estate prior to a transaction where either property transferred from us is more than 50% of the property owned by the person immediately after completion of the transfer or as part of a restructuring transaction in order for us to become more competitive, deal with regulatory requirements or respond to changes in the utility industry

generally. The Indenture also provides that, upon meeting certain specified conditions, in connection with the merger of a subsidiary into us, we can assume Qualifying Securities of the subsidiary issued under a Qualifying Securities Indenture that are payable to a person other than us or the Trustee.

Additional Obligations

The principal amount of Obligations that can be issued under the Indenture is not limited except as may be limited by law and, provided that, as described below, there must be a basis under the Indenture on which additional Obligations may be issued. Additional Obligations, ranking equally and ratably with all other Obligations, may be issued from time to time:

- (A) against:
 - (a) 90.91% of Bondable Additions;
 - (b) the aggregate principal amount of retired or defeased Obligations;
 - (c) the aggregate principal amount of Designated Qualifying Securities deposited with the Trustee;
 - (d) the amount of cash deposited with the Trustee (amounts so deposited as the basis for the issuance of additional Obligations (“Deposited Cash”)); and
 - (e) 90.91% of Certified Progress Payments (as described below);
- (B) to evidence reimbursement Obligations to Credit Enhancers in connection with Credit Enhancement or guarantees of other Obligations.

As of December 31, 2025, the balance of Bondable Additions under the Indenture was approximately \$567 million. As of December 31, 2025, the aggregate principal amount of retired or defeased Obligations not previously used as the basis for issuing additional Obligations was approximately \$271 million. The amount of any future Bondable Additions after December 31, 2025, will equal (i) the bondable value of all Property Additions not previously certified as Bondable Additions (as to which the lien of the Indenture shall be subject only to Permitted Exceptions), less (ii) property subject to the lien of the Indenture that is retired after December 31, 2025 (“Retirements”). Property Additions are limited under the Indenture to certain of our property that is chargeable to our fixed plant accounts, subject to the lien of the Indenture, acquired or constructed by us since January 1, 1998, and not subject to pre-existing liens securing indebtedness prior to or on a parity with the lien of the Indenture. For the purpose of calculating the amount of Property Additions and Retirements, the bondable value of property acquired after January 1, 1998, is the lesser of its cost or fair value to us (determined as of the time of acquisition). For the purpose of calculating Retirements, the amount of the Retirement for property acquired on or before January 1, 1998, is the net book value of such property as of January 1, 1998, and for property acquired after January 1, 1998, such Retirement is the value that such property was certified as a Property Addition, or if not so certified, then the cost of such property. See clause (2) of the definition of “Retired” herein for certain circumstances in which Bondable Property which might otherwise be treated as “Retired,” such as when an asset is retired from service for certain reasons prior to being fully depreciated, is deemed not to be “Retired” so long as we continue to recover the Depreciated Value (as defined below) of such Bondable Property in our rates.

Before we may (i) issue additional Obligations or (ii) assume any Qualifying Securities payable to a person other than us or the Trustee in connection with a merger of a subsidiary into us (see “—Merger of a Subsidiary into Us”), we must certify that our MFI Ratio was at least 1.10 during the immediately preceding fiscal year (or, if the certification is being made within 90 days after a fiscal year, we may use the second preceding fiscal year) or during any consecutive twelve-month period within the eighteen-month period immediately preceding our request for the issuance of additional Obligations or the assumption of Qualifying Securities.

Deposited Cash can be withdrawn against 90.91% of Bondable Additions, 90.91% of Certified Progress Payments, Retired or defeased Obligations of equivalent value or deposited Designated Qualifying Securities of equivalent value.

Events of Default and Remedies

The following are events of default that are applicable to all series of Obligations under the Indenture:

- (a) failure to pay principal of or premium, if any, on any Obligation when due or by the expiration of any grace period provided with respect to such Obligation (no payment by a guarantor or insurer of an Obligation shall be considered a payment for determining the existence of a failure to pay unless otherwise provided in such Obligation);
- (b) failure to pay any interest on any Obligation when due, continued for five (5) days or the grace period otherwise provided with respect to such Obligation (no payment by a guarantor or insurer of an Obligation shall be considered a payment for determining the existence of a failure to pay unless otherwise provided in such Obligation);
- (c) any other breach by us of any of our warranties or covenants contained in the Indenture, continued for 45 days after we have been provided written notice of default by the Trustee or the holders of at least 10% in aggregate principal amount of the outstanding Obligations;
- (d) failure to pay when due (giving effect to any applicable grace period) the principal of any of our indebtedness for money borrowed, which failure has resulted in the acceleration of indebtedness in excess of \$25 million, if such indebtedness is not discharged or such acceleration is not rescinded or annulled within 10 days after such failure or acceleration;
- (e) a judgment against us in excess of \$25 million which remains unsatisfied or unstayed for 45 days after either entry of judgment or termination of stay, and such judgment remains unstayed or unsatisfied for a period of 10 days after we have been provided written notice of default by the Trustee or by the holders of at least 10% in aggregate principal amount of the outstanding Obligations; or
- (f) certain other proceedings in bankruptcy, receivership, insolvency, liquidation or reorganization.

If an event of default described above should occur and be continuing, either the Trustee or the holders of at least 25% in aggregate principal amount of the outstanding Obligations may accelerate the maturity of all Obligations. However, after such acceleration, but before a sale of any of the Trust Estate or a judgment or decree based on acceleration, the holders of a majority in aggregate principal amount of outstanding Obligations may, under certain circumstances, rescind such acceleration if all events of default, other than the non-payment of accelerated principal, have been cured or waived as provided in the Indenture.

In addition to the events of default described above that are applicable to all series of Obligations, we may agree in a Supplemental Indenture to additional covenants or events of default under the Indenture for the benefit of a particular series of Obligations. Upon the occurrence of a series specific event of default, remedies (including acceleration) may be exercised by the holders of such series of Obligations in the same percentage as would be required for holders of all outstanding Obligations to exercise remedies in the case of events of default applicable to all series of Obligations. Such acceleration will not itself result in an event of default under the Indenture affecting all outstanding Obligations equally. However, if we fail to pay all amounts due upon such acceleration, an Indenture event of default relating to non-payment (see (a) and (b) above under “—Events of Default and Remedies”) would occur. To date, we have not provided in any Supplemental Indenture any covenants or events of default for the benefit of only a particular series of Obligations.

Subject to the provisions of the Indenture relating to the duties of the Trustee, in case an event of default should occur and be continuing, the Trustee is under no obligation to exercise any of its rights or powers under the Indenture at the request or direction of any of the holders, unless such holders shall have offered to the Trustee security or indemnity reasonably satisfactory to the Trustee. Subject to provisions for the indemnification of the Trustee, the holders of a majority in aggregate principal amount of the outstanding Obligations have the right, during the continuance of an event of default, to direct the time, method and place of conducting any proceeding for any remedy available to the Trustee or exercising any trust or power conferred on the Trustee.

No holder of any Obligation has any right to institute any proceeding with respect to the Indenture or for any remedy thereunder, unless

- (A) such holder had previously given to the Trustee written notice of a continuing event of default;
- (B) the holders of at least 25% in aggregate principal amount of the outstanding Obligations had made written request to the Trustee to institute such proceeding as Trustee and offered to the Trustee indemnity reasonably satisfactory to the Trustee;
- (C) the Trustee for 60 days after its receipt of such notice, request and offer of indemnity had failed to institute any such proceeding; and
- (D) the Trustee had not received from the holders of a majority in aggregate principal amount of the outstanding Obligations a direction inconsistent with such request.

Such limitations on the holders' rights to institute proceedings would not apply to a suit instituted by a holder of an Obligation for the enforcement of payment of the principal of, and premium, if any, and interest on such Obligation on or after the respective due dates expressed in such Obligation.

The Indenture provides that the Trustee, within 90 days after the occurrence of the event of default (but at least 60 days after the occurrence of certain specified events of default), shall give to the holders of Obligations notice of all uncured defaults known to it, provided that, except in the case of an event of default in the payment of principal of, and premium, if any, or interest on Obligations, the Trustee would be protected in withholding such notice if it in good faith determines that the withholding of such notice is in the interests of the holders of Obligations.

If an event of default should occur and be continuing, the Trustee, to the extent permitted by applicable law, may sell the property subject to the lien of the Indenture, in either judicial or nonjudicial proceeding, and the proceeds for disposition of such property shall be applied as follows:

- (A) first, the payment of all amounts due to the Trustee;
- (B) second,
 - (a) if all Obligations shall have become due and payable, to the payment of outstanding Obligations without preference or priority between interest or principal or redemption price (includes principal and redemption premium including any prepayment penalty) or among Obligations, or
 - (b) if the principal of all Obligations shall not have become due and payable, then (A) *first* to payment of interest installments then due in the order of their maturity, and if the amount available is not sufficient to pay in full the installments on such date, then ratably among such installments, according to amounts due; and (B) *second* to payment of principal or redemption price (includes principal and redemption premium, including any prepayment penalty), and if the amount available is not sufficient to pay in full all Obligations then due, then ratably, according to amounts of principal or redemption price (includes principal and redemption premium, including any prepayment penalty) due;

- (C) third, to payment of all other amounts due in connection with the Outstanding Secured Obligations including, but not limited to, penalties, premiums, costs and expenses payable to the holders;
- (D) fourth, to payment of amounts to maintain the value of reserve funds relating to certain tax-exempt bonds; and
- (E) fifth, to us or whosoever may be lawfully entitled to receive any remaining amount.

The Indenture requires us to deliver to the Trustee, within 120 days after the end of each calendar year, a written statement as to our compliance (determined without regard to any grace period or notice requirement) with all obligations under the Indenture. In addition, we are required to deliver to the Trustee, promptly after any of our officers may be reasonably deemed to have knowledge of a default under the Indenture, a written notice specifying the nature and duration of the default and the action we are taking and propose to take with respect thereto.

Amendments and Supplemental Indentures

Waiver of Covenants

Our compliance with the covenants contained in the Indenture relating to (i) limitation on liens, (ii) payment of taxes, (iii) maintenance of properties, (iv) insurance, (v) delivery of annual compliance certificates and notices of default under the Indenture, (vi) establishing and reviewing certain Rates, and (vii) distributions to the members, may be waived by a vote of the holders of a majority of the aggregate principal amount of Obligations outstanding.

Supplemental Indentures Without Consent of Holders

Without the consent of the holders of any Obligations, we and the Trustee will be able, from time to time, to enter into one or more Supplemental Indentures:

- to correct or amplify the description of any property at any time subject to the lien of the Indenture;
- to confirm property subject or required to be subjected to the lien of the Indenture or to subject additional property to the lien of the Indenture;
- to add to the conditions, limitations and restrictions on the authorized amount, terms or purposes of the issue, authentication and delivery of Obligations or of any series of Obligations under the Indenture;
- to create any new series of Obligations;
- to modify or eliminate any of the terms of the Indenture, provided that, in the event any such modification or elimination would adversely affect or diminish the rights of the holders of any Obligations outstanding, such Supplemental Indenture shall state that any such modification or elimination shall become effective only when there are no Obligations outstanding under any series created prior to such Supplemental Indenture, and provided the Trustee may decline to execute such Supplemental Indenture which, in its opinion, does not afford adequate protection to the Trustee;
- to evidence the succession of another corporation to us and the assumption by any such successor of our covenants;
- to add to the covenants or the events of default for the benefit of all or any series of Obligations or to surrender any of our rights or powers;

- to evidence the succession of another trustee or the appointment of a co-trustee or separate trustee;
- to cure any ambiguity, to correct or supplement any provision in the Indenture which may be inconsistent with any other provision or to make any other provisions, with respect to matters or questions arising under the Indenture, which shall not be inconsistent with the provisions of the Indenture, provided such action shall not adversely affect the interests of the holders of the Obligations in any material respect;
- to modify, eliminate or add to the provisions of the Indenture to the extent necessary to effect the qualification of the Indenture under any federal statute;
- to add or change any provisions of the Indenture to the extent necessary to permit or facilitate the issuance of Obligations in bearer or book-entry form;
- to provide for the assumption by us of Qualifying Securities issued and outstanding under any Qualifying Securities Indenture; or
- to make any change in the Indenture that, in the reasonable judgment of the Trustee, would not materially and adversely affect the rights of holders of Obligations. A Supplemental Indenture will be presumed not to materially and adversely affect the rights of holders if (i) the Indenture, as so supplemented and amended, secures equally and ratably the payment of principal of (and premium, if any) and interest on the Obligations which are to remain outstanding and (ii) we furnish to the Trustee written evidence from at least two nationally recognized statistical rating organizations then rating the Obligations (or other obligations primarily secured by Obligations) that their respective ratings of the Obligations (or other obligations primarily secured by Obligations) will not be withdrawn or reduced as a result of the changes in the Indenture effected by such Supplemental Indenture, provided that any changes in the Indenture that require the consent of all of the holders of Obligations affected thereby may not be made on the basis that they do not materially and adversely affect the rights of holders. See “—Supplemental Indentures With Consent of Holders.”

Supplemental Indentures With Consent of Holders

With the consent of the holders of not less than a majority in principal amount of the Obligations of all series then outstanding affected by such Supplemental Indenture, we and the Trustee may, from time to time, enter into one or more Supplemental Indentures to add, change or eliminate any of the provisions of the Indenture or modify the rights of the holders of such Obligations, but no such Supplemental Indenture may, without the consent of the holder of each outstanding Obligation affected thereby:

- change the date on which the principal of an Obligation or an installment of principal or interest on any Obligation is due and payable;
- reduce the principal of, or any installment of interest on, any Obligation, or any premium payable upon the redemption thereof;
- change any place of payment (the city or political subdivision thereof in which we are required by the Indenture to maintain an office or agency for payment of the principal of or interest on the Obligations) where any Obligation, or the interest thereon, is payable, or change the currency in which any payment on any Obligation is payable;
- impair the right to institute suits for the enforcement of any such payment on or after the stated maturity thereof (or, in the case of redemption, on or after the redemption date);
- reduce the percentage of holders of outstanding Obligations needed for certain Supplemental Indentures or to waive non-compliance with provisions of, or certain defaults under, the Indenture;

- revise the definitions of “Outstanding” and “Outstanding Secured Obligations” as such definitions relate to Obligations owned by us or one of our affiliates;
- modify the unconditional right of holders to institute suit for enforcement of any principal, interest or premium due on Obligation;
- revise the percentage of holders of outstanding Obligations needed for waivers of default, except to increase such percentage;
- revise the Indenture provision specifying the Supplemental Indentures requiring the consent of each holder affected thereby, except by adding to the Indenture provisions that may not be modified except with such consent of all affected holders;
- permit the creation of any lien ranking prior to or on a parity with the lien of the Indenture with respect to any of the Trust Estate; or
- modify the provisions of any mandatory sinking fund so as to affect the rights of a holder to the benefits thereof.

Consolidation, Merger, Conveyance or Transfer

The Indenture provides that we will not consolidate with or merge into any other person or convey or transfer the Trust Estate substantially as an entirety to any person, unless:

- the consolidation, merger, conveyance or transfer is on terms that fully preserve the lien and security of the Indenture as provided for in the Indenture and the rights and powers of the Trustee and the holders of Obligations;
- the successor is an entity organized and validly existing under the laws of the United States of America, any state thereof or the District of Columbia;
- the successor executes and delivers to the Trustee a Supplemental Indenture in accordance with the requirements of the Indenture in which (i) the successor assumes the due and punctual payment of the principal of, and premium, if any, and interest on all the outstanding Obligations and the performance and observance of every covenant and condition of the Indenture that we would otherwise have to perform or observe and (ii) there is a grant, conveyance, transfer and mortgage complying with the Indenture;
- immediately after giving effect to the transaction, no event of default under the Indenture will exist; and
- we deliver to the Trustee an officers’ certificate and an opinion of counsel, each of which state that such consolidation, merger, conveyance or transfer and the related Supplemental Indenture comply with the requirements of the Indenture and that all conditions precedent provided for in the Indenture relating to the transaction have been complied with.

In the case of any such consolidation, merger, conveyance or transfer, the Indenture is not required to be a lien upon any of the properties then owned or thereafter acquired by the successor entity other than upon:

- betterments, extensions, improvements, additions, repairs, renewals, replacements, substitutions and alterations to or upon the property subject to the lien of the Indenture;
- property made the basis of withdrawal of cash from the Trustee or the release of property from the lien of the Indenture;
- property acquired or constructed with insurance proceeds, with proceeds from the release of any part of the property subject to the lien of the Indenture or with condemnation awards;

- property acquired to maintain and repair the property subject to the lien of the Indenture in accordance with the requirements of the Indenture;
- property acquired or constructed with Trust Moneys that consist of the proceeds of insurance; and
- all property, leases, rights-of-way, franchises, licenses, permits or easements acquired in alteration, substitution, surrender or modification of the same.

In the event the Indenture is not made a lien on any such properties then owned or thereafter acquired by the successor entity, no additional Obligations may be issued under the Indenture (other than Obligations issued in exchange or substitution for outstanding Obligations).

Merger of a Subsidiary into Us

The Indenture provides that a subsidiary who has issued Qualifying Securities pursuant to a Qualifying Securities Indenture may merge with us in accordance with the following terms (other than with respect to a merger of Dakota Coal with us which shall be effectuated in accordance with the provisions set forth in “– Consolidation, Merger, Conveyance or Transfer” above):

- all property, rights, privileges or franchises that are subject to the lien of the Qualifying Securities Indenture shall be transferred to us free and clear of the lien of the Qualifying Securities Indenture and shall be subjected to the lien of the Indenture by a Supplemental Indenture executed and delivered by us to the Trustee;
- the Trustee will receive written evidence from at least two nationally recognized statistical rating organizations then rating the Obligations (or other obligations primarily secured by Outstanding Secured Obligations) that their respective ratings of the Outstanding Secured Obligations (or other obligations primarily secured by Outstanding Secured Obligations) that are not subject to Credit Enhancement will not be withdrawn or reduced as a result of any such merger;
- immediately after giving effect to such merger, no event of default under the Indenture will exist;
- the Trustee will receive title evidence as to the property of the subsidiary and opinions and certificates relating to the merger and the property being transferred; and
- we deliver to the Trustee an officers' certificate and an opinion of counsel, each of which state that such merger complies with the requirements of the Indenture and that all conditions precedent provided for in the Indenture relating to the transaction have been complied with.

Upon completion of the merger, any balance of Bondable Additions of the subsidiary will be added to our balance of Bondable Additions and any Property Additions of the subsidiary that have been certified by the subsidiary as Bondable Additions will be deemed to be our Property Additions. In addition, Obligations that we issued on the basis of Designated Qualifying Securities of the subsidiary will be deemed to have been issued upon the basis upon which the subsidiary issued the Designated Qualifying Securities under its Qualifying Securities Indenture.

Action by Credit Enhancer

With respect to Obligations issued prior to May 5, 2015, except as otherwise provided in a Supplemental Indenture authorizing Obligations of a series or a maturity within a series, if not in default in respect of any of its Obligations with respect to Credit Enhancement for such Obligations, the Credit Enhancer for, and not the actual holders of, such Obligations, will at all times be deemed to be the holder of such Obligations for the purpose of (i) giving any approval or consent to the effectiveness of any Supplemental Indenture or any amendment, change or modification of the Indenture which requires the written approval or consent of holders of Obligations of such series, other than any changes which cannot be made under the Indenture without the consent of the holders of each Obligation thereby as described

above under “– Amendments and Supplemental Indentures – Supplemental Indentures With Consent of Holders” and (ii) giving any other approval or consent, giving any notice, effecting any waiver or authorization, exercising any remedies or taking any other action in accordance with the provisions of the Indenture. With respect to Obligations issued on or after May 5, 2015, the foregoing provision will be applicable if it is provided for in a Supplemental Indenture authorizing a series of Obligations but only with respect to the authorized series.

Defeasance

Subject to certain other conditions, the Indenture provides that Obligations of any series, or any maturity within a series, will be deemed to have been paid and any of our Obligations to the holders of such Obligations will be discharged (subject, in the case of Obligations outstanding on May 5, 2015, to receipt of rulings or opinions relating to tax matters), if we deposit with the Trustee or paying agent cash or Defeasance Securities maturing as to principal and interest in such amounts and at such times as are sufficient, without consideration of reinvestment of such interest, to pay when due the principal or (if applicable) redemption price and interest due and to become due on such Obligations.

Concerning the Trustee

U.S. Bank Trust Company, National Association is the trustee under the Indenture and is also serving as Exchange Agent in connection with the Exchange Offer. We may maintain other banking relationships in the ordinary course of business with affiliates of U.S. Bank Trust Company, National Association for which they may receive customary fees.

Governing Law

The Indenture is, and the Exchange Bonds will be, governed by and construed in accordance with the laws of the State of North Dakota.

Definitions

Set forth below is a summary of defined terms from the Indenture that are used in this [“SUMMARY OF THE INDENTURE.”](#) Reference is made to the Indenture for the full definition of all such terms as well as any other capitalized terms used herein for which no definition is provided. Unless the context otherwise requires, an accounting term not otherwise defined has the meaning assigned to it in accordance with GAAP.

“Bondable Additions” means the excess of (i) the amount of Property Additions over (ii) the amount of Retirements (less credits thereto), computed in accordance with the Indenture and certified as Bondable Additions in the summary of certificate as to Bondable Additions then being filed in accordance with the Indenture.

“Bondable Property” means all Property Additions, and all property owned by the Company on the Cut-Off Date which would constitute Property Additions if acquired after that date (except for the requirement to deliver title evidence with respect to such property).

“Certified Progress Payments” means payments, made by the Company under or in connection with a Qualified EPC Contract, for generation and related facilities (including electric transmission and fuel supply facilities) that will constitute Property Additions upon the performance of such Qualified EPC Contract, that are certified by the Company to the Trustee as the basis for (i) the withdrawal of Deposited Cash under the Indenture, (ii) loans or advances under conditional Obligations under the Indenture, (iii) the authentication and delivery of additional Obligations under the Indenture or (iv) the withdrawal and payment of Trust Moneys under the Indenture.

“Cut-Off Date” means January 1, 1998.

“Defeasance Securities” means and includes any of the following securities, if and to the extent the same are not subject to redemption or call prior to maturity by anyone other than the holder thereof and are at the time legal for investment of the Company’s funds:

- (A) any bonds or other obligations which as to principal and interest constitute direct obligations of, or are unconditionally guaranteed by, the United States of America; and
- (B) any certificates or any other evidences of an ownership interest in obligations or in specified portions thereof (which may consist of specified portions of the interest thereon) of the character described in paragraph A above.

“Deposited Cash” means cash (which may be cash representing the purchase price of, or the proceeds of a loan or advance evidenced by the additional Obligations to be authenticated and delivered under the Indenture) equal to the aggregate principal amount of the additional Obligations whose authentication and delivery are then applied for under the Indenture.

“Designated Qualifying Securities” means, as of the date of determination, such Qualifying Securities held by the Trustee which have been designated by the Company (i) pursuant to the Indenture as the basis for the issuance and delivery of additional Obligations, (ii) pursuant to the Indenture as the basis for the withdrawal of Deposited Cash, (iii) pursuant to the Indenture as the basis for the advance or issuance of any unadvanced or unissued portion of any conditional Obligation or series of conditional Obligations, (iv) pursuant to the Indenture as the basis for the release of property, (v) pursuant to the Indenture as the basis for the withdrawal of Trust Moneys or (vi) pursuant to of the Indenture as the basis for surrender or redesignation of other Designated Qualifying Securities; subject in all such cases to redesignation or surrender thereof pursuant to the Indenture.

“Excludable Property” means property with respect to which an officers’ certificate has been delivered to the Trustee pursuant to paragraph E of the third paragraph of the definition of “Property Additions” below, the output of such property, and all property rights, privileges and franchises of every kind and description, real, personal or mixed, tangible or intangible, whether now owned or hereafter acquired by the Company, wherever located, including, without limitation, goods (including equipment, fuel, materials and supplies), accounts and general intangibles relating solely to such certified property or the output of such property.

“Interest Charges” for any period means the total interest charges (whether capitalized or expensed) of the Company for such period on all Outstanding Secured Obligations and outstanding prior lien Obligations, in all cases including amortization of debt discount and premium on issuance but excluding all interest accruing in respect of Obligations authenticated and delivered on the basis of Qualifying Securities issued by a wholly-owned subsidiary of the Company if such subsidiary is required under such Qualifying Securities Indenture to earn Margins for Interest of not less than 1.10 times Interest Charges under a rate covenant substantially identical in substance to Section 13.14 of the Indenture and such Designated Qualifying Securities bear interest at the rate of interest to accrue on the Obligations authenticated and delivered on the basis of such Designated Qualifying Securities, determined in accordance with accounting requirements.

“Margins for Interest” means, for any period, the sum of (i) net margins of the Company for such period, which shall include revenues of the Company, if any, subject to possible refund at a later date; provided, however, no deductions shall be made as a result of refunds ordered in a subsequent period; plus (ii) Interest Charges; plus (iii) accruals of Federal income and other taxes imposed on income after deduction of Interest Charges for such period; plus (iv) the amount, if any, included in net margins for any losses incurred by any subsidiary or affiliate of the Company other than amounts included pursuant to clause (viii) below; plus (v) the amount, if any, the Company actually receives in such period as a dividend or other distribution of earnings of any subsidiary or affiliate (whether or not such earnings were for such period or any earlier period or periods) which amount has not otherwise been reflected as an increase in net margins; plus (vi) the amount of any expenses or provisions for any non-recurring charge to income or

margins or retained earnings of whatever kind or nature (including, without limitation, the recognition of expense due to the non-recoverability of assets or expenses) that may have been deducted or otherwise taken into account in arriving at net margins whether or not recorded as a non-recurring charge in the Company's books of account; minus (vii) the amount, if any, included in net margins for any income, gain, earnings or profits of any subsidiary or affiliate of the Company other than amounts included pursuant to clause (v) above; and minus (viii) the amount, if any, the Company actually contributes to the capital of, or actually pays under a guarantee by the Company of an obligation of, any subsidiary or affiliate in such period to the extent of any accumulated losses incurred by such subsidiary or affiliate (whether or not such losses were for such period or any earlier periods), but only to the extent (x) such losses have not otherwise caused other contributions or payments to be included in net margins for purposes of computing Margins for Interest for a prior period and (y) such amount has not otherwise been included in net margins. Margins for Interest shall be determined in accordance with accounting requirements; provided, however, that such determination shall be made on a Company only and not on a consolidated basis.

"Obligations" means, collectively, the new notes, bonds and other obligations for the payment of money as provided in the Indenture issued on or after May 5, 2015, in one or more series, together with all Obligations outstanding.

"Outstanding Secured Obligations" means, as of the date of determination, (i) all Obligations then outstanding other than Obligations then owned by the Company or any wholly-owned subsidiary and held in its treasury and (ii) all Obligations, if any, alleged to have been destroyed, lost or stolen which have been replaced or paid as provided in the Indenture but whose ownership and enforceability by the holder thereof have been established by a court of competent jurisdiction or other competent tribunal or otherwise established to the satisfaction of the Company and the Trustee.

"Permitted Exceptions" means:

- A. as to the property described in subdivisions A and B of granting clause First of the Indenture, the restrictions, exceptions, reservations, terms, conditions, agreements, leases, subleases, covenants, limitations, interests and other matters which are of record on the date such property becomes subject to the lien of this Indenture; provided, that such matters do not materially impair the use of such property for the purposes for which it is held by the Company;
- B. as to property which the Company may acquire after May 5, 2015, any restriction, exception, reservation, term, condition, agreement, covenant, limitation, interest or other matter which is of record on the date of such acquisition or expressed or provided in the deeds or other instruments under which the Company shall acquire the same, provided, with respect to an acquisition of property of a subsidiary in connection with a merger of a subsidiary into the Company pursuant to the Indenture, any such restriction, exception, reservation, term, condition, agreement, covenant, limitation, interest or other matter of record on the date of such acquisition or expressed or provided in the deeds or other instruments under which the Company acquires such property shall constitute a Permitted Exception hereunder only if the foregoing constituted a permitted exception under the Qualifying Securities Indenture of such subsidiary, provided, further, that all such matters do not materially impair the use of such property for the purposes for which it is held by the Company;
- C. liens for taxes, assessments and other governmental charges not delinquent, and ordinances establishing assessments for sewer, lighting or other local improvement districts;
- D. liens for taxes, assessments and other governmental charges already delinquent which are currently being contested in good faith by appropriate proceedings and with respect to which the Company shall have set aside on its books adequate reserves with respect thereto if such reserves are required by accounting requirements;

- E. mechanics', workmen's, repairmen's, materialmen's, warehousemen's, contractors', subcontractors' and carriers', liens and other similar liens arising in the ordinary course of business or incident to current construction for charges which (i) are not delinquent or (ii) are being contested in good faith and have not proceeded to judgment and with respect to which the Company shall have set aside on its books adequate reserves with respect thereto if such reserves are required by accounting requirements;
- F. liens in respect of judgments or awards (i) with respect to which the Company shall in good faith currently be prosecuting an appeal or proceedings for review and shall have secured a stay of execution pending such appeal or proceedings for review, provided the Company shall have set aside on its books adequate reserves with respect thereto if such reserves are required by accounting requirements or (ii) which are fully covered by insurance;
- G. easements and rights granted by the Company under the Indenture and similar rights granted by any predecessor in title of the Company;
- H. easements, leases, restrictions, rights-of-way, exceptions, reservations or other rights of others in any property of the Company for streets, roads, expressways, bridges, pipes, pipe lines, railroads, towers, poles, wires, conduits, mains, metering stations, electric, electronic, optical, or other power or signal transmission and distribution lines, telecommunications and telephone lines, the removal of oil, gas, coal or other minerals, and other similar purposes, flood rights, river control and development rights, sewage and drainage rights, restrictions against pollution and zoning laws and minor defects and irregularities in the record evidence of title of any property, to the extent that such easements, leases, restrictions, rights-of-way, exceptions, reservations, other rights, laws, defects and irregularities do not in the aggregate materially impair the use of the Trust Estate taken as a whole for the purposes for which it is held by the Company;
- I. liens upon lands over which easements, licenses or rights-of-way are acquired by the Company for any of the purposes specified in paragraph H of this definition, securing indebtedness neither created, assumed nor guaranteed by the Company nor on account of which it customarily pays interest;
- J. leases or permits for occupancy existing at January 1, 1998, affecting property owned by the Company at said date (and future modifications, renewals and extensions thereof);
- K. leases to, and permits for occupancy by, other persons entered into after January 1, 1998, affecting property owned by the Company, whether acquired before or after the date of this instrument (i) for a term of not more than ten (10) years (including any extensions or renewals) or (ii) if for a term of more than ten (10) years which do not materially impair the Company's use of the property in the conduct of its business;
- L. any lien or privilege vested in any lessor, landlord, licensor, permittor or other person for rent to become due or for other obligations or acts to be performed, the payment of which rent or the performance of which other obligations or acts is required under leases, usufructs, subleases, licenses or permits, so long as the payment of such rent or the performance of such other obligations or acts is (i) not delinquent or (ii) being contested in good faith and has not proceeded to judgment and with respect to which the Company shall have set aside on its books adequate reserves with respect thereto if such reserves are required by accounting requirements;
- M. liens or privileges of any employees of the Company for salary or wages earned but not yet payable;
- N. the burdens of any law or governmental regulation, license or permit requiring the Company to maintain certain facilities or perform certain acts as a condition of the carrying on of the Company's business or the occupancy of or interference with any public lands or any river or stream or navigable waters;

- O. any restrictions, covenants, defects or irregularities in or other deficiencies of title to any easement or rights-of-way of or used by the Company for pipe lines, telephone lines, telecommunications lines, power lines, towers, poles, wires, conduits, mains, electric transmission lines and distribution lines, substations, metering stations, signal transmission and distribution lines or for similar purposes, to any real property of the Company owned in fee used or to be used by the Company primarily for such purposes, or to any appurtenances to any such easement, right-of-way or real property or other improvements on any such easement, right-of-way or real property, if (i) in the case of easements or rights-of way, the Company shall have obtained from the apparent owner of the lands or estates therein covered by any such easement or right-of-way a sufficient right, by the terms of the instrument granting such easement or right-of-way, to the use thereof for the construction, operation or maintenance of the lines, appurtenances or improvements for which the same are used or are to be used, (ii) the Company has power under eminent domain, or similar statutes, to remove such restrictions, covenants, defects, irregularities or other deficiencies, or (iii) such restrictions, covenants, defects, irregularities or other deficiencies may be otherwise remedied without undue effort or expense;
- P. rights reserved to, or vested in, any municipality or governmental or other public authority to control or regulate any property of the Company or the use thereof, or to use such property in any manner, which rights do not materially impair the use of such property for the purposes for which it is held by the Company;
- Q. any obligations or duties, affecting the property of the Company, to or established by any municipality or governmental or other public authority in connection with any franchise, grant, license or permit;
- R. any right which any municipal or governmental authority may have by virtue of any franchise, license, contract or statute;
- S. any restrictions, including restrictions on transfer, liens or other matters arising from, permitted by, or required by, any law or governmental regulation relating to environmental matters so long as such restrictions, liens or other matters do not materially impair the use of such property for the purposes for which it is held and as to any liquidated liens with respect thereto, the Company shall have set aside on its books adequate reserves with respect thereto if such reserves are required by accounting requirements;
- T. reservations contained in U.S. patents;
- U. slope and drainage reservations;
- V. deposits to secure duties or public or statutory obligations, deposits to secure, or in lieu of, surety, stay or appeal bonds, and deposits as security for the payment of taxes or assessments or similar charges;
- W. any lien or other matter required by law or governmental regulation as a condition to the transaction of any business or the exercise of any privilege or license, or to enable the Company to maintain self-insurance or to participate in any funds established to cover any insurance risks or in connection with worker's compensation, unemployment insurance, retirement pensions or other social security, or to share in the privileges or benefits required for companies participating in such arrangements;
- X. any lien or other encumbrance created or assumed by the Company in connection with the issuance of debt securities the interest on which is excludable from gross income of the holder of such security pursuant to the Internal Revenue Code of 1986, as amended, for the purposes of financing or refinancing, in whole or in part, the acquisition or construction of property used or to be used by the Company to the extent such lien covers only such acquired or constructed property and the proceeds upon the sale, transfer or exchange thereof;

- Y. the pledge of current assets, in the ordinary course of business, to secure current liabilities;
- Z. liens or other encumbrances securing indebtedness for the payment of which money or Defeasance Securities, maturing as to principal and interest in such amounts and at such times, as are sufficient to provide for the full and timely payment of such indebtedness shall have been irrevocably deposited in trust or escrow with the trustee or other holder of such lien, and liens on such deposited money or Defeasance Securities, provided that if such indebtedness is to be redeemed or otherwise prepaid prior to the stated maturity thereof, any notice requisite to such redemption or prepayment shall have been irrevocably given in accordance with the mortgage or other instrument creating such lien or other encumbrance or irrevocable instructions to give such notice shall have been given to such trustee or other holder;
- AA. the undivided or other interest of other owners, and liens on such interest, in property owned in common or jointly with the Company or in which the Company has an executory or future interest, and all rights of such co-owners or joint owners in such property, including the rights of such owners to such property pursuant to ownership contracts;
- BB. any liens or other encumbrances of any person arising on account of the ownership in common or jointly with the Company of an undivided or other interest in property which relate to amounts which are not due and payable, or which are being contested by the Company in good faith, and with respect to which the Company shall have set aside on its books adequate reserves with respect thereto if such reserves are required by accounting requirements; and
- CC. liens which have been bonded for the full amount of the obligations secured by such lien or for the payment of which the Company has deposited with the Trustee or with an escrow agent cash or other property with a value equal to the full amount of the obligations secured by such lien.

“Property Additions” means property as to which the Company shall provide title evidence (which, as to Retired property, may be dated as of a date immediately prior to the Retirement) and which shall be (or, if Retired, shall have been) subject to the lien of this Indenture, which shall be properly chargeable to the Company’s fixed plant accounts under accounting requirements (including property acquired to replace property Retired and credited to such accounts) and which shall be acquired by the Company after the Cut-Off Date, including property in the process of construction, insofar as not reflected on the books of the Company with respect to periods on or prior to the Cut-Off Date. Property Additions need not consist of a specific or completed development, plan, betterment, addition, extension, improvement or enlargement, but may include construction work in progress and property in the process of purchase insofar as title has been vested in the Company.

“Property Additions” shall also include:

- A. easements and rights-of-way that are useful for the conduct of the business of the Company;
- B. property located or constructed (i) on, over or under public highways, rivers or other public property if the Company has the lawful right under permits, licenses or franchises granted by a governmental body having jurisdiction in the premises or by the law of the state in which such property is located or (ii) on, over or under other property subject to easements and rights of way described in paragraph A above, if the Company has the right under such permits, licenses, franchises, law, easements or rights of way to maintain and operate such property for an unlimited, indeterminate or indefinite period or for the period, if any, specified in such permit, license, franchise, law, easement or right of way and to remove such property at the expiration of the period covered by such permit, license, franchise, law, easement or right of way or if the terms of such permit, license, franchise, law, easement or right of way require any public authority or grantor thereof having the right to take over such property to pay fair consideration therefor; and

- C. tangible property, which would be properly chargeable to the Company's fixed plant accounts under accounting requirements (including property acquired to replace property Retired and credited to such accounts) if title were vested in the Company, if (i) such property itself (in addition to the Company's leasehold interest in such property) is subject to the lien of the Indenture and (ii) such property is leased to the Company.

"Property Additions" shall not include:

- A. good will, going concern value, contracts, agreements, franchises, licenses or permits, whether acquired as such, separate and distinct from the property operated in connection therewith, or acquired as an incident thereto;
- B. Stock, indebtedness or other securities, including certificates or evidences of interest therein;
- C. any property that is to remain subject to a prior lien (except to the extent permitted by the Indenture) after the granting of the related application, or subject to the Permitted Exception described in paragraph X of the definition of "Permitted Exceptions";
- D. except as provided in paragraph C above, any plant or system or other property in which the Company shall acquire only a leasehold interest, or any betterments, extensions, improvements or additions (other than movable physical personal property which the Company has the right to remove), of, upon or to any plant or system or other property in which the Company shall own only a leasehold interest unless in the case of betterments, extensions, improvements or additions of, upon or to any plant or system or other property in which the Company shall own only a leasehold interest (i) the term of the leasehold interest in the property to which such betterment, extension, improvement or addition relates (including any periods for which the Company has the option to extend or renew such leasehold interest) shall extend for at least 75% of the estimated useful economic life of such betterment, extension, improvement or addition and (ii) the lessor shall have agreed to give the Trustee reasonable notice and opportunity to cure any default by the Company under such lease and not to disturb the Trustee's possession of such leasehold estate in the event the Trustee succeeds to the Company's interest in such lease upon the Trustee's exercise of any remedies under this Indenture so long as there is no default in the performance of the tenant's covenants contained therein;
- E. property otherwise constituting Property Additions, but with respect to which the Company has delivered to the Trustee, prior to the Company's acquisition of such property, an officers' certificate specifically identifying such property to be acquired and stating that (i) such property is not to be subject to the lien of this Indenture and (ii) if the Company does not have the use of such property, it would remain capable of complying with the requirements of the Indenture; or
- F. property otherwise constituting Property Additions which has been (i) acquired from a subsidiary, (ii) previously subject to the lien and security interest of a Qualifying Securities Indenture, (iii) previously certified as Bondable Property under such Qualifying Securities Indenture and (iv) used as the basis on which Qualifying Securities which have been unconditionally assumed by the Company were issued.

"Qualified EPC Contract" means any contract providing for the engineering, procurement or construction of generation or related facilities (including electric transmission and fuel supply facilities) intended to be owned by the Company, payments made under or in connection with which are used as the basis for (i) loans or advances under conditional Obligations under the Indenture or (ii) the authentication and delivery of additional Obligations under the Indenture.

"Qualifying Securities" means bonds or other instruments evidencing indebtedness for borrowed money or purchase money indebtedness issued and outstanding under a Qualifying Securities Indenture.

“Qualifying Securities Indenture” means any indenture, mortgage, deed to secure debt, deed of trust or similar instrument entered into by any subsidiary of the Company or, in the case of a transaction described in the last sentence hereof, by any person, (i) which contains provisions (and related definitions) substantially identical in substance to the provisions (and related definitions) contained in this Indenture (with such variations and omissions as are appropriate in view of the fact that the subsidiary and not the Company is a party thereto), except that it may omit or have different provisions (and related definitions) relating to (a) the need to deliver an available margins certificate upon the authentication and delivery of Qualifying Securities issued thereunder, (b) the requirement to establish and collect the rates, rents, charges, fees and other compensation of such subsidiary reasonably expected to yield any particular level of Margins for Interest, (c) limiting distributions or dividends, and (d) such other matters as the Trustee shall determine in its reasonable judgment do not materially and adversely affect the value of the Qualifying Securities issued thereunder as security for the Obligations; provided, however, that in making any such determination the Trustee may rely upon certificates of investment bankers or other financial professionals or consultants, and (ii) under which Qualifying Securities are issued. A Qualifying Securities Indenture may be entered into by any person that succeeds to the Company’s interest in any property constituting part of the Trust Estate prior to such transaction where either (i) the property transferred from the Company is more than 50% of the property owned by the Person immediately after the completion of the transfer or (ii) after the transfer the person will be engaged in providing utility services to the Company or to entities that were direct or indirect customers of the Company immediately prior to the transfer and the Company delivers a certificate to the Trustee, simultaneously with the issuance of the Qualifying Securities, that certifies that the property constituting part of the Trust Estate was transferred to the person as part of a plan of the Company to restructure in order to be more competitive, deal with regulatory requirements or respond to changes in the utility industry generally (collectively, referred to hereinafter as a “restructuring transaction”).

“Retired” means, when used with respect to property, Bondable Property that, since the Cut-Off Date, has been retired, abandoned, destroyed, worn out, removed, permanently discontinued, lost through the enforcement of any liens or released, sold or otherwise disposed of free of the lien of this Indenture or taken by eminent domain or under the exercise of a right of a government authority to purchase or take the same or recorded as retired on the books of the Company or permanently retired from service for any reason, whether or not replaced, or shall have permanently ceased to be used or useful in the business of the Company, including as a consequence of the termination of any lease, whether or not recorded as retired on the books of the Company, except that,

- A. when a minor item of property has been replaced by other property of equal value and efficiency and the cost of such replacement has been charged to other than fixed property accounts such as maintenance, repairs or other similar account, the property replaced shall not be considered as Retired; and
- B. if, with respect to Bondable Property that would otherwise be considered Retired in circumstances where such Bondable Property becomes unfit or uneconomical for use in the Company’s business or the use of such Bondable Property for its intended purpose becomes prohibited by applicable law or governmental action, (i) such Bondable Property has permanently ceased to be used or useful in the Company’s business, (ii) the Board of Directors of the Company has approved the recovery in Rates of the value of such Bondable Property as such value is recorded on the books of the Company (taking into account depreciation) on the date of such approval (the “Depreciated Value”), and (iii) any regulatory approvals or determinations needed at the time for such recovery have been obtained, then such Bondable Property shall not be considered as Retired until the earlier of (a) the date the Depreciated Value of such Bondable Property has been fully recovered in Rates or (b) on the date the Depreciated Value of such Bondable Property is no longer being recovered in Rates.

“Supplemental Indenture” means any indenture supplemental to the Indenture and duly authorized in the manner provided in the Indenture.

“Trust Estate” means all such property, rights, privileges and franchises by the Indenture and thereafter (by Supplemental Indenture or otherwise) granted, bargained, sold, alienated, remised, released, conveyed, assigned, transferred, mortgaged, hypothecated, pledged, set over or confirmed as aforesaid, or intended, agreed or covenanted so to be, together with all the tenements, hereditaments and appurtenances thereto appertaining (said properties, rights, privileges and franchises, including any cash and securities hereafter deposited or required to be deposited with the Trustee (other than any such cash which is specifically stated herein not to be deemed part of the Trust Estate)).

“Uniform Commercial Code” means, with respect to any particular part of the Trust Estate, the Uniform Commercial Code as enacted and in effect from time to time in the state whose laws are treated as applying to such part of the Trust Estate.

CERTAIN U.S. FEDERAL INCOME TAX CONSIDERATIONS

This general discussion of certain U.S. federal income tax considerations applies to you if you acquired Original Bonds for cash in the offering of the Original Bonds for their issue price, exchange the Original Bonds for Exchange Bonds pursuant to the Exchange Offer and hold the Exchange Bonds as a “capital asset,” as defined in Section 1221 of the Code. This discussion, however, does not address state, local or foreign tax laws or any U.S. federal tax laws other than income tax laws (such as estate or gift tax laws). In addition, it does not describe all of the rules which may affect the U.S. federal income tax treatment of the Exchange Offer or your investment in the Exchange Bonds. For example, special rules not discussed here may apply to you if you are:

- a broker-dealer, a dealer in securities, a trader in securities or a bank or other financial institution;
- an S corporation, partnership or other pass-through entity (or an investor in such an entity);
- an insurance company;
- a tax-exempt entity;
- a person subject to the alternative minimum tax provisions of the Code;
- a “controlled foreign corporation,” “passive foreign investment company,” or a corporation that accumulates earnings to avoid U.S. federal income tax;
- a U.S. Holder (as defined below) who holds Original Bonds or Exchange Bonds through a non-U.S. broker or other non-U.S. intermediary;
- a person holding Original Bonds or Exchange Bonds as part of a hedge, straddle, conversion transaction or other risk reduction or constructive sale transaction;
- subject to the mark-to-market method of tax accounting;
- a “controlled foreign corporation,” “passive foreign investment company” or a corporation that accumulates earnings to avoid U.S. federal income tax.
- required to prepare certified financial statements or file financial statements with certain regulatory or governmental agencies;
- an expatriate of the United States; or
- a U.S. person whose functional currency is not the U.S. dollar.

If a partnership (or an entity that is treated as a partnership) holds Original Bonds or Exchange Bonds, the tax treatment of such partnership (or entity that is treated as a partnership) and a partner in such partnership (or entity that is treated as a partnership) generally will depend upon the status of the partner and upon the activities of the partnership (or entity that is treated as a partnership). If you are a partnership (or any entity that is treated as a partnership) or a partner of a partnership (or entity that is treated as a partnership) considering an investment in the Exchange Bonds, we suggest that you consult your tax advisor.

This discussion is a summary of certain U.S. federal income tax considerations that may apply to you based on current U.S. federal income tax law as available and in effect. This discussion is based on current provisions of the Code, U.S. Treasury regulations, published rulings, and court decisions, all as available and in effect as of the date hereof and all of which are subject to change or differing interpretations, possibly with retroactive effect. There can be no assurances that the IRS or any court will agree with the statements and conclusions in this discussion.

There are certain tax reform proposals currently being considered. While it is uncertain whether any such proposals would be enacted into law, and it is impossible to predict whether this will be the case, if any such proposals were to become law, they could materially change the U.S. federal income tax consequences described below.

This discussion may not cover your particular circumstances because it does not consider foreign, state or local tax rules or U.S. federal tax rules other than income tax rules, disregards certain special U.S. federal income tax rules, and does not describe future changes in U.S. federal income tax rules. Please consult your tax advisor rather than relying on this general discussion.

Exchange of Original Bonds for Exchange Bonds Pursuant to the Exchange Offer

The exchange of Original Bonds for Exchange Bonds pursuant to the Exchange Offer generally will not be treated as a taxable exchange for U.S. federal income tax purposes. The remainder of this discussion assumes that the exchange of Original Bonds for Exchange Bonds pursuant to the Exchange Offer will not be treated as a taxable exchange for U.S. federal income tax purposes. Your U.S. federal income tax basis in the Original Bonds will carry over to the Exchange Bonds received pursuant to the Exchange Offer and the holding period of the Exchange Bonds will include the holding period of Original Bonds surrendered.

U.S. Holders of Exchange Bonds

If you are a “U.S. Holder,” as defined below, of Exchange Bonds, this section applies to you. If you are a “Non-U.S. Holder,” as defined below, of Exchange Bonds, the next section, “Non-U.S. Holders,” may apply to you.

Definition of U.S. Holder

For purposes of this discussion, you are a “U.S. Holder” if you are a beneficial owner of Exchange Bonds that, for U.S. federal income tax purposes, is:

- an individual who is a citizen or resident of the United States, including an alien individual who is a lawful permanent resident of the United States or who meets the “substantial presence” test under Section 7701(b) of the Code;
- a corporation created or organized under the laws of the United States, any state thereof or the District of Columbia;
- an estate, the income of which is subject to U.S. federal income tax regardless of its source; or
- a trust, if a U.S. court can exercise primary supervision over the administration of the trust and one or more U.S. persons can control all substantial decisions of the trust, or if the trust was in existence on August 20, 1996 and has elected to continue to be treated as a U.S. person.

Stated Interest

You must generally include stated interest on the Exchange Bonds in income as ordinary income:

- when you receive it, if you use the cash method of accounting for U.S. federal income tax purposes; or
- as it accrues, if you use the accrual method of accounting for U.S. federal income tax purposes.

Sale or Other Taxable Disposition of Exchange Bonds

You generally will recognize taxable gain or loss on a sale, exchange, redemption, retirement or other taxable disposition of an Exchange Bond equal to the difference, if any, between the amount you receive for the Exchange Bond (in cash or other property, valued at fair market value), other than amounts

attributable to accrued and unpaid interest on the Exchange Bond, which will be taxed in the manner described above, and your U.S. federal income tax basis in the Exchange Bond. Your U.S. federal income tax basis in a Bond generally will equal your cost for the Original Bond exchanged for the Exchange Bond pursuant to the Exchange Offer.

Any gain or loss recognized on a sale, exchange, redemption, retirement or other taxable disposition of an Exchange Bond will generally be a long-term capital gain or loss if you have held the Exchange Bond for more than one year. Otherwise, it will be a short-term capital gain or loss. Non-corporate U.S. Holders currently may be eligible for a reduced rate of taxation on long-term capital gain. The deductibility of capital losses is subject to limitations.

Defeasance of the Exchange Bonds

If we defease any Exchange Bond, such Exchange Bond may be deemed to be retired for U.S. federal income tax purposes as a result of the defeasance. In that event, in general, you will recognize taxable gain or loss equal to the difference between (i) the amount deemed to be realized from the deemed sale, exchange or retirement (less any accrued qualified stated interest which will be taxable as such) and (ii) your adjusted U.S. federal income tax basis in the Exchange Bond.

Additional Tax on Investment Income

Certain individuals, estates and trusts are required to pay a 3.8% tax on “net investment income” including, among other things, interest and proceeds of sales or other dispositions in respect of securities (such as the Exchange Bonds), subject to certain exceptions. You should consult your own tax advisors regarding the effect, if any, of this tax on your acquisition, ownership and disposition of Exchange Bonds.

Non-U.S. Holders of Exchange Bonds

Definition of Non-U.S. Holder

For purposes of this discussion, a “Non-U.S. Holder” is a beneficial owner of Exchange Bonds that, for U.S. federal income tax purposes, is an individual, corporation, estate or trust that is not a U.S. Holder.

Interest

In general, subject to the discussions below under “Backup Withholding and Information Reporting” and “Foreign Account Tax Compliance Act (“FATCA”),” interest income of a Non-U.S. Holder that is not effectively connected with a United States trade or business will not be subject to U.S. federal income tax under the “portfolio interest exemption” if:

- you represent that you are the beneficial owner of Exchange Bonds and not a U.S. person for U.S. federal income tax purposes and you provide your name and address to the applicable withholding agent on a properly executed IRS Form W-8 (or a suitable substitute form) signed under penalties of perjury; or
- a securities clearing organization, bank or other financial institution that holds customers’ securities in the ordinary course of its trade or business holds the Exchange Bonds on your behalf, certifies to the applicable withholding agent under penalty of perjury that it has received a properly executed IRS Form W-8 (or a suitable substitute form) from you or from another qualifying financial institution intermediary, and provides a copy to the applicable withholding agent; and
- you do not own, actually or constructively, 10% or more of the total combined voting power of all classes of our capital stock which is entitled to vote;
- you are not a controlled foreign corporation with respect to which we are a “related person” within the meaning of Section 864(d)(4) of the Code; or

- you are not a bank receiving interest described in Section 881(c)(3)(A) of the Code.

Special certification rules apply to foreign partnerships, estates, and trusts, and in certain circumstances, certifications as to the foreign status of partners, trust owners, or beneficiaries may have to be provided to the applicable withholding agent. In addition, special certification rules apply to payments made through a qualified intermediary.

If you do not claim, or do not qualify for, the benefit of the portfolio interest exemption, you will be subject to a 30% withholding tax on payments of interest made on the Exchange Bonds that are not effectively connected with a United States trade or business unless you are able to claim the benefit of a reduced withholding tax rate under an applicable income tax treaty with the United States. The required information for claiming treaty benefits is generally submitted on an applicable IRS Form W-8BEN (or a suitable substitute form).

Except to the extent that an applicable income tax treaty otherwise provides, (i) a Non-U.S. Holder will be taxed on a net income basis in generally the same manner as a U.S. Holder with respect to interest that is effectively connected with a United States trade or business of the Non-U.S. Holder, and (ii) a corporate Non-U.S. Holder may also, in some circumstances, be subject to a “branch profits tax” at a 30% rate (or, if applicable, a lower treaty rate) on its effectively connected earnings and profits (subject to adjustments). Even though effectively connected interest is subject to income tax, and may be subject to the branch profits tax, it is not subject to withholding tax if the holder delivers a properly executed IRS Form W-8ECI or other applicable form (or a suitable substitute form) to the applicable withholding agent.

Sale or Other Taxable Disposition of Exchange Bonds

Subject to the discussions below under “Backup Withholding and Information Reporting” and “Foreign Account Tax Compliance Act (“FATCA”),” you generally will not be subject to U.S. federal income tax or withholding tax on any gain recognized on a sale, exchange, redemption, retirement, or other taxable disposition of an Exchange Bond unless (i) the gain is effectively connected with a U.S. trade or business (and, in the case of certain income tax treaties, is attributable to a permanent establishment within the United States), in which case such gain generally will be taxed in the same manner as effectively connected interest (as described above) and a corporate Non-U.S. Holder may also be subject to a “branch profits tax” at a 30% rate (or, if applicable, a lower treaty rate) on its effectively connected earnings and profits (subject to adjustments) or (ii) you are an individual who was present in the United States for 183 days or more in the taxable year of the disposition and certain other conditions are met, in which case you generally will be subject to a U.S. federal income tax of 30% (or a reduced treaty rate) on such gain (net of certain U.S. source losses). In the event that a payment is attributable to accrued and unpaid interest, the rules applicable to payments of interest described above will apply.

Foreign Account Tax Compliance Act (“FATCA”)

Under Sections 1471 through 1474 of the Code (“FATCA”), U.S. federal withholding tax may apply to certain types of payments made to “foreign financial institutions,” as specially defined under such rules, and certain other non-U.S. entities. FATCA generally imposes a 30% withholding tax on certain types of payments to a foreign financial institution unless (a) the foreign financial institution enters into an agreement with the U.S. Treasury to provide certain information regarding such institution’s account holders and owners of its equity or debt, (b) in the case of a foreign financial institution in a jurisdiction that has entered into an intergovernmental agreement with the United States, complies with the requirements of such agreement, or (c) the foreign financial institution otherwise is exempt from FATCA withholding. In addition, FATCA imposes a 30% withholding tax on the same types of payments to certain non-financial foreign entities unless the applicable entity certifies that it does not have any substantial U.S. owners or furnishes identifying information regarding each substantial U.S. owner. In general, FATCA withholding currently applies to payments of interest on the Exchange Bonds and, under current guidance would apply to certain “passthru” payments no earlier than the date that is two years after

publication of final U.S. Treasury Regulations defining the term “foreign passthru payments”. Prospective investors should consult their tax advisors regarding this legislation.

Backup Withholding and Information Reporting

Backup withholding may apply in respect of interest payments made to a holder of Exchange Bonds and proceeds from a sale or other disposition (including a retirement or redemption) of Exchange Bonds, unless such holder provides proof of an applicable exemption or provides a correct taxpayer identification number and otherwise complies with applicable requirements of the backup withholding rules. Any amounts withheld under the backup withholding rules are not an additional tax and may be refunded, or credited against the holder’s U.S. federal income tax liability, provided that the required information is timely furnished to the IRS. In addition, information returns generally will be filed with the IRS in connection with interest payments on the Exchange Bonds and the proceeds from a sale or other disposition (including a redemption or retirement) of the Exchange Bonds unless the holder provides proof of an applicable exemption from the information reporting rules.

The regulations governing information reporting and backup withholding are complex, and this summary does not completely describe them. Please consult your tax adviser to determine how the applicable regulations will affect your particular circumstances.

The preceding discussion of certain U.S. federal income tax considerations is for general information only. It is not tax advice. Each prospective investor should consult its tax adviser regarding the particular U.S. federal, state, local and foreign tax consequences of purchasing, holding, and disposing of Exchange Bonds, including the consequences of any proposed change in applicable laws.

PLAN OF DISTRIBUTION

Based on existing interpretations of the Securities Act by the SEC staff set forth in several no-action letters to third parties (including *Exxon Capital Holdings Corporation* (available May 13, 1988), *Morgan Stanley & Co. Incorporated* (available June 5, 1991), and *Shearman & Sterling* (available July 2, 1993)), and subject to the immediately following sentence, we believe that the Exchange Bonds issued pursuant to the Exchange Offer in exchange for Original Bonds may be offered for resale, resold and otherwise transferred by the holders thereof (other than holders that are broker-dealers) without further compliance with the registration and prospectus delivery provisions of the Securities Act. However, any holder of Original Bonds that intends to participate in the Exchange Offer for the purpose of distributing the Exchange Bonds or that is an affiliate of ours that does not comply with the registration and prospectus delivery requirements of the Securities Act to the extent applicable in connection with the resale of the Exchange Bonds, or any broker-dealer that purchased any of the Original Bonds from us or any of our affiliates for resale pursuant to Rule 144A or any other available exemption under the Securities Act, (i) will not be able to rely on the interpretations of the SEC staff set forth in the above-mentioned no-action letters, (ii) will not be entitled to tender its Original Bonds in the Exchange Offer, and (iii) must comply with the registration and prospectus delivery requirements of the Securities Act in connection with any sale or transfer of the Original Bonds unless such sale or transfer is made pursuant to an exemption from such requirements.

Each broker-dealer that receives Exchange Bonds for its own account pursuant to the Exchange Offer must acknowledge that it will deliver a prospectus in connection with any resale of such Exchange Bonds. This prospectus, as it may be amended or supplemented from time to time, may be used by a broker-dealer in connection with resales of Exchange Bonds received in exchange for Original Bonds where such Original Bonds were acquired as a result of market-making activities or other trading activities. We have agreed to keep effective the registration statement of which this prospectus is a part until the earlier of 180 days after the completion of the Exchange Offer or such time as broker-dealers no longer own any Exchange Bonds. In addition, until August 4, 2026 (90 days after the date of this prospectus), all dealers effecting transactions in the Exchange Bonds may be required to deliver a prospectus.

We will not receive any proceeds from any sale of Exchange Bonds by broker-dealers. Exchange Bonds received by broker-dealers for their own account pursuant to the Exchange Offer may be sold from time to time in one or more transactions in the over-the-counter market, in negotiated transactions, through the writing of options on the Exchange Bonds or a combination of such methods of resale, at market prices prevailing at the time of resale, at prices related to such prevailing market prices or negotiated prices. Any such resale may be made directly to purchasers or to or through brokers or dealers who may receive compensation in the form of commissions or concessions from any such broker-dealer or the purchasers of any such Exchange Bonds. Any broker-dealer that resells Exchange Bonds that were received by it for its own account pursuant to the Exchange Offer and any broker or dealer that participates in a distribution of such Exchange Bonds may be deemed to be an “underwriter” within the meaning of the Securities Act and any profit of any such resale of Exchange Bonds and any commissions or concessions received by any such persons may be deemed to be underwriting compensation under the Securities Act. The letter of transmittal states that by acknowledging that it will deliver and by delivering a prospectus, a broker-dealer will not be deemed to admit that it is an “underwriter” within the meaning of the Securities Act.

For a period of 180 days after the expiration date of the Exchange Offer (or until the broker-dealer no longer holds registrable securities), we will promptly send additional copies of this prospectus and any amendment or supplement to this prospectus to any broker-dealer that requests such documents in the letter of transmittal. Subject to certain limitations set forth in the Registration Rights Agreement, we have agreed to pay all expenses incident to the Exchange Offer other than commissions or concessions of any brokers or dealers and will indemnify the holders of the Original Bonds (including any broker-dealers) against certain liabilities, including liabilities under the Securities Act.

LEGAL MATTERS

The validity of the Exchange Bonds will be passed upon for us by Matthew R. Kolling, our Senior Staff Counsel.

EXPERTS

The financial statements of Basin Electric Power Cooperative as of December 31, 2025 and 2024, and for each of the three years in the period ended December 31, 2025, included in this Prospectus, have been audited by Deloitte & Touche LLP, an independent registered public accounting firm, as stated in their report. Such financial statements are included in reliance upon the report of such firm given their authority as experts in accounting and auditing.

Financial Statements and Supplementary Data

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the members and the Board of Directors of Basin Electric Power Cooperative

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of Basin Electric Power Cooperative and subsidiaries (the "Cooperative") as of December 31, 2025 and 2024, the related consolidated statements of operations, comprehensive income, cash flows and changes in equity for each of the three years in the period ended December 31, 2025, and the related notes (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Cooperative as of December 31, 2025 and 2024, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2025, in conformity with accounting principles generally accepted in the United States of America.

Basis for Opinion

These financial statements are the responsibility of the Cooperative's management. Our responsibility is to express an opinion on the Cooperative's financial statements based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Cooperative in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. The Cooperative is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits, we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of the Cooperative's internal control over financial reporting. Accordingly, we express no such opinion.

Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

Critical Audit Matter

The critical audit matter communicated below is a matter arising from the current-period audit of the financial statements that was communicated or required to be communicated to the audit committee and that (1) relates to accounts or disclosures that are material to the financial statements and (2) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the financial statements, taken as a whole, and we are not, by communicating the critical audit matter below, providing a separate opinion on the critical audit matter or on the accounts or disclosures to which it relates.

Regulatory Assets and Liabilities — Refer to Notes 2 and 9 to the financial statements

Critical Audit Matter Description

The Cooperative is subject to rate regulation by its Board of Directors, which establishes electric rates to customers that are subject to acceptance by the United States Department of Agriculture Rural Utilities Service (RUS). Management has determined it meets the requirements under accounting principles generally accepted in the United States of America to prepare its financial statements applying the

specialized rules to account for the effects of cost-based rate regulation. Accounting for the economics of rate regulation affects multiple financial statement line items and disclosures, including property, plant and equipment, regulatory assets and liabilities, operating revenues and expenses, and income taxes.

Rates are subject to regulatory rate-setting processes and are determined in order to recover the cost of service and to comply with the Cooperative's Indenture covenants and other contractual commitments and to establish reasonable reserves. Decisions by the Board of Directors and RUS in the future will impact the accounting for regulated operations, including decisions about the amount of allowable costs and return on invested capital included in rates and any refunds that may be required. In the rate setting process, the Cooperative's rates result in the recording of regulatory assets and liabilities based on the probability of future cash flows. Regulatory assets generally represent incurred or accrued costs that have been deferred because future recovery from customers is probable. Regulatory liabilities generally represent amounts that are expected to be refunded to customers in future rates or amounts collected in current rates for future costs.

We identified the impact of rate regulation as a critical audit matter due to the significant judgments made by management to support its assertions about impacted account balances and disclosures and the high degree of subjectivity involved in assessing the impact of future resolutions of the Board of Directors or regulatory orders on the financial statements. Management judgments include assessing the likelihood of recovery in future rates of incurred costs and requirements to refund amounts to customers. Given that management's accounting judgments are based on assumptions about the outcome of future decisions by the Board of Directors and RUS, auditing these judgments required specialized knowledge of accounting for rate regulation and the rate setting process due to its inherent complexities.

How the Critical Audit Matter Was Addressed in the Audit

Our audit procedures related to the uncertainty of future decisions by the Board of Directors and RUS included the following, among others:

- We inspected minutes of the Board of Directors and regulatory orders issued by the RUS, and recommendations being evaluated by the RUS, and other publicly available information to assess the likelihood of recovery in future rates or of a future reduction in rates. We compared the minutes of the Board of Directors, regulatory orders and other publicly available information to the Cooperative's recorded regulatory assets and liabilities for completeness.
- We inquired of management about property, plant, and equipment that may be abandoned or retired prior to the end of its useful life. We inspected minutes of the Board of Directors and other filings with the RUS to identify any evidence that may contradict management's assertion regarding probability of an abandonment.
- We evaluated the Cooperative's financial statement presentation and disclosures related to the impacts of rate regulation, including the balances recorded and regulatory developments.

/s/ Deloitte & Touche LLP

Minneapolis, Minnesota

April 15, 2026

We have served as the Cooperative's auditor since 2002.

BASIN ELECTRIC POWER COOPERATIVE AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
as of December 31,

Assets

	2025	2024
	(In thousands)	
Property, plant and equipment:		
Plant in service	\$ 10,252,773	\$ 9,397,849
Construction work in progress	778,763	831,772
Less: accumulated provision for depreciation and amortization	(4,375,917)	(4,169,001)
Net property, plant and equipment	6,655,619	6,060,620
Other assets and investments:		
Mine related assets	166,561	151,425
Investments in associated companies	37,024	36,240
Restricted and designated investments	61,362	54,313
Other investments	138,624	261,073
Special funds	69,564	69,489
Total other assets and investments	473,135	572,540
Current assets:		
Cash and cash equivalents	685,570	376,659
Restricted and designated cash and cash equivalents	301,923	317,251
Short-term investments	630	13,136
Receivables – Members	202,408	191,436
Receivables, net	117,228	117,094
Inventories	358,812	320,582
Prepayments and other current assets	118,837	102,988
Total current assets	1,785,408	1,439,146
Regulatory assets	311,373	295,157
Other deferred charges	172,122	127,319
Total deferred charges	483,495	422,476
Total Assets	\$ 9,397,657	\$ 8,494,782

The accompanying notes are an integral part of these consolidated financial statements.

BASIN ELECTRIC POWER COOPERATIVE AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS, Continued
as of December 31,

Capitalization and Liabilities

	2025	2024
	(In thousands)	
Capitalization:		
Equity:		
Memberships	\$ 22	\$ 22
Patronage capital	1,523,238	1,476,557
Retained earnings of subsidiaries	142,776	125,713
Other equity	294,252	285,113
Accumulated other comprehensive income	13,463	4,806
	<u>1,973,751</u>	<u>1,892,211</u>
Noncontrolling interest	2,676	2,711
Total Equity	1,976,427	1,894,922
Long-term debt	4,949,264	4,588,373
Finance lease obligations	3,532	4,305
Total capitalization	6,929,223	6,487,600
Commitments and contingencies (Note 17)		
Current liabilities:		
Long-term debt and finance leases due within one year	177,134	194,264
Accounts payable	421,715	315,719
Notes payable – Members	159,495	142,390
Notes payable	475,000	200,000
Other current liabilities	196,460	145,404
Total current liabilities	1,429,804	997,777
Deferred credits and other:		
Regulatory liabilities	336,305	337,241
Deferred income tax liability	90,922	82,008
Other noncurrent liabilities	611,403	590,156
Total deferred credits and other	1,038,630	1,009,405
Total Capitalization and Liabilities	\$ 9,397,657	\$ 8,494,782

The accompanying notes are an integral part of these consolidated financial statements.

BASIN ELECTRIC POWER COOPERATIVE AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS
for the years ended December 31,

	2025	2024	2023
	(In thousands)		
Operating revenue:			
Sales - Members (related party)	\$2,162,056	\$1,995,959	\$1,926,214
Other operating revenues (includes related party of \$272,191, \$225,241, and \$229,330, respectively)	925,715	819,440	960,904
Total operating revenues	3,087,771	2,815,399	2,887,118
Operating expenses:			
Electric fuel and purchased power (includes related party of \$183,343, \$149,029, and \$152,929, respectively)	1,116,603	1,074,416	1,077,496
Electric operations and maintenance (includes related party of \$(5,666), \$(9,916), and \$(9,988), respectively)	758,006	679,558	662,056
Cost of products sold (includes related party of \$64,717, \$60,496, and \$61,112, respectively)	597,232	542,295	544,439
Nonelectric selling, general and administrative (includes related party of \$29,797, \$25,632, and \$25,277, respectively)	114,612	47,782	38,905
Depreciation, depletion and amortization	276,761	259,477	249,500
Impairment of assets	4,164	36,296	5,035
Total operating expenses	2,867,378	2,639,824	2,577,431
Operating margin	220,393	175,575	309,687
Other income:			
Investment income	75,022	88,091	89,247
Other and tax credits	128,248	132,148	19,161
Total other income	203,270	220,239	108,408
Interest and other charges:			
Interest expense	305,800	297,233	265,762
Interest charged during construction	(27,939)	(32,376)	(10,059)
Total interest and other charges	277,861	264,857	255,703
Margin before income taxes	145,802	130,957	162,392
Income tax expense (benefit)	6,530	(13,037)	(6,207)
Net margin and earnings including noncontrolling interest	139,272	143,994	168,599
Net margin and earnings attributable to noncontrolling interest	(23,000)	(23,215)	(21,083)
Net margin and earnings attributable to Basin Electric	\$ 116,272	\$ 120,779	\$ 147,516

The accompanying notes are an integral part of these consolidated financial statements.

BASIN ELECTRIC POWER COOPERATIVE AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
for the years ended December 31,

	2025	2024	2023
	(In thousands)		
Net margin and earnings including noncontrolling interest ...	\$ 139,272	\$ 143,994	\$ 168,599
Other comprehensive income (loss):.....			
Adjustment to post employment liability (net of tax of \$750, \$(44), and \$13, respectively)	4,180	2,826	4,010
Unrealized gain on securities (net of tax of \$29, \$305, and \$725, respectively)	104	1,070	2,706
Reclassification of net realized (gain) loss on securities (net of tax of \$29, \$(2), and \$13, respectively)	(110)	9	50
Unrealized gain (loss) on cash flow hedges (net of tax of \$1,465, \$(686), and \$3,651, respectively)	5,511	(2,578)	13,736
Reclassification of net realized gain on cash flow hedges (net of tax of \$(273), \$(600), and \$(6,338), respectively)	(1,028)	(2,259)	(23,839)
Total other comprehensive income (loss)	8,657	(932)	(3,337)
Comprehensive income including noncontrolling interest	147,929	143,062	165,262
Comprehensive income attributable to noncontrolling interest	(24,358)	(26,207)	(25,046)
Comprehensive income attributable to Basin Electric	<u>\$ 123,571</u>	<u>\$ 116,855</u>	<u>\$ 140,216</u>

The accompanying notes are an integral part of these consolidated financial statements.

BASIN ELECTRIC POWER COOPERATIVE AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY
for the years ended December 31, 2025, 2024, and 2023

	Memb ership s	Patronage Capital	Retained Earnings of Subsidiaries	Other Equity	Accumulated Other Comprehensive Income	Noncontrolling Interest	Total
(In thousands)							
Balance, December 31, 2022	\$ 21	\$ 1,228,756	\$ 120,410	\$ 346,348	\$ 9,075	\$ 5,006	\$ 1,709,616
Comprehensive income (loss)	-	150,254	(2,738)	-	(7,300)	-	140,216
Transfers to other equity	-	59,931	-	(59,931)	-	-	-
Purchase of memberships	1	-	-	-	-	-	1
Retirement of patronage capital	-	(42,975)	6,302	-	-	-	(36,673)
Comprehensive income attributable to noncontrolling interest	-	-	-	-	3,963	21,083	25,046
Dividends paid to noncontrolling interest	-	-	-	-	-	(24,268)	(24,268)
Balance, December 31, 2023	22	1,395,966	123,974	286,417	5,738	1,821	1,813,938
Comprehensive income (loss)	-	125,872	(5,093)	-	(3,924)	-	116,855
Transfers to other equity	-	1,304	-	(1,304)	-	-	-
Retirement of patronage capital	-	(46,585)	6,832	-	-	-	(39,753)
Comprehensive income attributable to noncontrolling interest	-	-	-	-	2,992	23,215	26,207
Dividends paid to noncontrolling interest	-	-	-	-	-	(22,325)	(22,325)
Balance, December 31, 2024	22	1,476,557	125,713	285,113	4,806	2,711	1,894,922
Comprehensive income	-	104,735	11,537	-	7,299	-	123,571
Transfers to other equity	-	(9,139)	-	9,139	-	-	-
Retirement of patronage capital	-	(48,915)	5,526	-	-	-	(43,389)
Comprehensive income attributable to noncontrolling interest	-	-	-	-	1,358	23,000	24,358
Dividends paid to noncontrolling interest	-	-	-	-	-	(23,035)	(23,035)
Balance, December 31, 2025	\$ 22	\$ 1,523,238	\$ 142,776	\$ 294,252	\$ 13,463	\$ 2,676	\$ 1,976,427

The accompanying notes are an integral part of these consolidated financial statements.

BASIN ELECTRIC POWER COOPERATIVE AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
for the years ended December 31,

	2025	2024	2023
	(In thousands)		
Operating activities:			
Net margin and earnings attributable to Basin Electric	\$ 116,272	\$ 120,779	\$ 147,516
Adjustments to reconcile net margin and earnings to net cash provided by operating activities:			
Depreciation, amortization and accretion	337,226	349,157	296,852
Deferred income taxes	(1,109)	(15,564)	(12,725)
Changes in regulatory assets and liabilities	2,230	(63,792)	(58,826)
Unrealized gain on investments	(7,327)	(12,034)	(11,384)
Patronage capital allocated	(6,752)	(7,224)	(8,444)
Income attributable to noncontrolling interest	23,000	23,215	21,083
Recognition of initial payment for tax credits	(11,483)	(20,657)	-
Changes in other operating elements:			
Receivables	(10,738)	(26,421)	51,739
Inventories	(39,741)	(31,333)	(52,948)
Prepayments and other current assets	(10,118)	(1,708)	(10,009)
Accounts payable	17,368	7,039	56,800
Other current liabilities	27,742	(18,679)	(166,396)
Other operating activities, net	(28,125)	(40,232)	5,399
Net cash provided by operating activities	<u>408,445</u>	<u>262,546</u>	<u>258,657</u>
Investing activities:			
Capital expenditures	(807,224)	(645,126)	(524,639)
Proceeds from sales of property	14,589	3,910	1,783
Purchase of investments	(67,656)	(1,138,995)	(1,300,771)
Sale of investments	188,374	1,517,156	1,607,266
Changes in other investments, net	(6,632)	(3,727)	(655)
Net cash used in investing activities	<u>(678,549)</u>	<u>(266,782)</u>	<u>(217,016)</u>
Financing activities:			
Proceeds from sale of membership interest	-	167,467	-
Proceeds from issuance of long-term debt	816,270	479,600	80,000
Principal payments of long-term debt	(458,557)	(212,331)	(88,692)
Payment of debt issuance costs	(13,365)	(2,875)	(383)
Changes in notes payable – Members, net	12,704	(94,728)	(12,776)
Changes in short-term borrowings, net	275,000	(36,964)	685
Retirement of patronage capital	(43,389)	(39,753)	(36,673)
Dividends paid to noncontrolling interest	(23,035)	(22,325)	(24,268)
Other	(1,941)	(1,138)	(810)
Net cash provided by (used in) financing activities	<u>563,687</u>	<u>236,953</u>	<u>(82,917)</u>
Net increase (decrease) in cash and cash equivalents and designated cash and equivalents	<u>293,583</u>	<u>232,717</u>	<u>(41,276)</u>
Cash and cash equivalents and restricted and designated cash and equivalents, beginning of period	693,910	461,193	502,469
Cash and cash equivalents and restricted and designated cash and equivalents, end of period	<u>\$ 987,493</u>	<u>\$ 693,910</u>	<u>\$ 461,193</u>

The accompanying notes are an integral part of these consolidated financial statements.

BASIN ELECTRIC POWER COOPERATIVE AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS, Continued
for the years ended December 31,

	<u>2025</u>		<u>2024</u>		<u>2023</u>
	(In thousands)				
Supplemental cash flow information:					
Cash paid for interest	\$	258,649	\$	257,934	\$ 241,791
Cash paid (refunded) for income taxes	\$	153	\$	2,411	\$ (603)
Supplemental disclosure of noncash investing and financing activities:					
Accrued acquisition of property, plant and equipment	\$	120,736	\$	40,042	\$ 66,828
Operating lease additions	\$	33,678	\$	14,745	\$ 14,695

The accompanying notes are an integral part of these consolidated financial statements.

BASIN ELECTRIC POWER COOPERATIVE AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. ORGANIZATION

Basin Electric Power Cooperative (Basin Electric) is an electric generation and transmission cooperative corporation, organized and existing under the laws of the State of North Dakota. It serves member electric service needs in a nine-state region of North Dakota, South Dakota, Montana, Wyoming, New Mexico, Colorado, Nebraska, Minnesota and Iowa. Basin Electric's power supply resources are composed of its own generating facilities and contractual power purchase arrangements. Basin Electric owns and operates transmission assets, some of which are a part of the Southwest Power Pool and others which are jointly owned.

The rates charged to its members for electric service are established by Basin Electric's Board of Directors with changes in rates subject to acceptance by the United States Department of Agriculture Rural Utilities Service (RUS).

Basin Electric has three wholly owned for-profit subsidiaries, Dakota Gasification Company (Dakota Gas), Dakota Coal Company (Dakota Coal), and Nemadji River Generation (NRG). Basin Electric also has one wholly owned not-for-profit subsidiary, Basin Cooperative Services (BCS). Dakota Gas has a wholly owned for-profit subsidiary, Souris Valley Pipeline Limited (SVPL). Dakota Coal has a wholly owned for-profit subsidiary, Montana Limestone Company (MLC). Dakota Gas owns and operates the Great Plains Synfuels Plant (Synfuels Plant) which converts lignite coal into pipeline-quality synthetic gas and produces a number of other products including anhydrous ammonia, urea, diesel exhaust fluid (DEF), carbon dioxide (CO₂), tar oil and chemical products. The Synfuels Plant is located adjacent to Basin Electric's Antelope Valley Station (AVS) electric generating plant. These plants share certain facilities, and coal and water supplies. Dakota Gas supplies various Basin Electric gas generating stations and AVS with synthetic gas. SVPL owns and operates a CO₂ pipeline in Saskatchewan, Canada. Dakota Coal purchases lignite coal from the Freedom Mine, a coal mine in North Dakota that is owned and operated by The Coteau Properties Company (Coteau), a wholly owned subsidiary of The North American Coal Corporation (NACoal). NACoal is a wholly owned subsidiary of NACCO Industries, Inc. (NACCO). Coteau is a variable interest entity (VIE) of Dakota Coal. Pursuant to the coal purchase agreement, Dakota Coal is obligated to provide financing for and has certain rights with respect to the operation of the coal mine. The lignite coal is used in Basin Electric's Leland Olds Station (LOS), AVS, and Dakota Gas's Synfuels Plant. Dakota Coal coordinates procurement and rail delivery of Powder River Basin coal to the Laramie River Station (LRS) and the Dry Fork Station (DFS). Dakota Coal also owns a lime plant that sells lime to AVS, the Laramie River Station (LRS) and others. MLC operates a limestone quarry and owns and operates a fine grind plant, both in Montana, and sells limestone to Dakota Coal's lime plant, LOS and others. BCS provides certain nonutility property management services to Basin Electric. Basin Electric is a 42.27 percent owner of the Missouri Basin Power Project (MBPP) and acts as the operating agent for the 1,700 megawatt LRS generating plant in Wyoming, associated transmission facilities and the Grayrocks Dam and Reservoir. Basin Electric's ownership in MBPP is accounted for using proportionate consolidation consistent with accounting for jointly owned utility property. NRG was a 30 percent owner in the Nemadji Trail Energy Center (NTEC) project, which was a proposed 600 megawatt combined cycle generating plant in Wisconsin. In January 2026, NRG exited the NTEC project.

Dakota Carbon Services LLC (DCS), a Delaware limited liability company, was incorporated in October 2023. DCS was formed to own and operate carbon capture assets in North Dakota and to contract for transportation and sequestration of CO₂. In February 2024, an LLC agreement was entered into by DGC with a tax equity partner to monetize tax credits available under Section 45Q of the United States Internal Revenue Code for the capture and sequestration of CO₂ (45Q transaction).

BASIN ELECTRIC POWER COOPERATIVE AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS, Continued

2. SIGNIFICANT ACCOUNTING POLICIES

PRINCIPLES OF CONSOLIDATION—The consolidated financial statements include the accounts of Basin Electric, its wholly owned subsidiaries and its VIE's, Coteau and DCS. DCS is considered a VIE for which Dakota Gas is the primary beneficiary. All intercompany investments, debt, and receivable and payable accounts have been eliminated in consolidation. Charges from BCS, Dakota Gas, Dakota Coal, MLC and Coteau to Basin Electric and charges from Basin Electric to BCS, Dakota Gas, Dakota Coal, MLC and Coteau are not eliminated as Basin Electric includes the results of these activities in the determination of rates charged to its members (Note 19).

N-7 LLC (N-7) is a Delaware limited liability company formed by OCI Iowa, Inc. (OCI) and Dakota Gas on May 18, 2018. N-7 was formed to market OCI's, Dakota Gas's and other companies' fertilizer and DEF production. N-7 is considered a VIE of Dakota Gas for which Dakota Gas is not the primary beneficiary and, therefore, Dakota Gas is not required to consolidate N-7. However, Dakota Gas has the ability to exercise significant influence over N-7. Therefore, Dakota Gas's share of N-7 net income is recorded in the consolidated financial statements using the equity method of accounting. The investment in N-7 is included in other investments on the consolidated balance sheets and Dakota Gas' share of N-7 net income is presented in other and tax credits income in the consolidated statements of operations.

In 2024, Dakota Gas and OCI agreed to dissolve N-7 with final dissolution to be completed in the first half of 2026. Basin Electric does not anticipate this to have a material impact on the consolidated financial statements and disclosures.

USE OF ESTIMATES—The preparation of consolidated financial statements in conformity with accounting principles generally accepted in the United States of America (GAAP) requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the consolidated financial statements and the reported amounts of revenue and expenses during the reporting period. Estimates are used for items such as present value of lease assets and lease liabilities, plant depreciable lives, actuarially determined benefit costs, valuation of derivatives, asset retirement obligations, present value of expected tax credits, cash flows used in asset impairment evaluations and income tax expense or benefits. Ultimate results could differ from those estimates.

CASH AND CASH EQUIVALENTS—Basin Electric considers all investments purchased with an original maturity of three months or less to be cash equivalents. The fair value of cash equivalents approximates their carrying values due to their short-term maturity.

RESTRICTED AND DESIGNATED CASH AND INVESTMENTS—Basin Electric has certain restricted cash and investments for MBPP operating funds. Other restricted investments are held in trust by a financial institution for SVPL asset retirement obligations. Basin Electric's Board of Directors designates additional cash and investments for deferred revenue purposes and for other asset retirement obligations. For more information, see Note 6.

INVESTMENTS—Investments include equity securities, corporate bonds, government obligations and bond market funds as well as the cash surrender value of life insurance policies. Investments in equity securities are measured at fair value with unrealized gains and losses recorded on the consolidated statements of operations for nonutility operations. For utility operations, the unrealized gain and losses are deferred as regulatory items using ASC 980, *Regulated Operations*. Basin Electric classifies its debt securities as either available-for-sale or held-to-maturity. Available-for-sale debt securities are measured at fair value and unrealized gains and losses are recorded in accumulated other comprehensive income. Held-to-maturity debt securities are measured at amortized cost. If any of Basin Electric's other investments experience a decline in value that is believed to be other than temporary, a loss is

BASIN ELECTRIC POWER COOPERATIVE AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS, Continued

recognized in other and tax credits income in the consolidated statements of operations. For more information, see Note 7.

INVENTORIES—Dakota Gas products available for sale and MLC limestone inventories are stated at the lower of average cost or net realizable value. Fuel stock, materials and supplies inventories are stated at average cost, which approximates market. Inventories were as follows at December 31:

	2025	2024
	(In thousands)	
Materials and supplies	\$ 245,857	\$ 221,836
Coal and fuel oil	62,238	67,009
Lime and limestone inventory	8,484	8,779
Ammonia	9,233	4,434
Urea	18,786	7,134
Natural gas held in storage	2,055	3,418
Ammonium sulfate	5,081	3,015
Other products	6,611	4,398
Process inventory	467	559
	\$ 358,812	\$ 320,582

PATRONAGE CAPITAL—At the discretion of Basin Electric’s Board of Directors, utility margins are allocated to members on a patronage basis or may be offset in whole or in part against current or prior losses. Basin Electric may not retire patronage capital if, after the distribution, an event of default would exist or Basin Electric’s equity would be less than 20 percent of total long-term debt and equity. Cumulative patronage capital retired was \$567.2 million and \$518.3 million at December 31, 2025 and 2024, respectively.

REVENUE RECOGNITION—Revenue is recognized when a performance obligation is satisfied which occurs when the control of the promised goods or services is transferred to customers. Revenue is measured based on the transaction price identified in the contract with a customer. The transaction price in a contract reflects the amount of consideration to which an entity expects to be entitled to in exchange for goods or services transferred. Payment terms vary by contract. Generally, payment is due within 30 days.

Revenue is derived from the electric utility, gasification, and coal and limestone operations.

Electric utility operations mainly consist of wholesale electricity sales to members pursuant to long-term wholesale electric service contracts and the sale of excess energy and ancillary services transacted through regional transmission organizations (RTOs) and short-term wholesale power agreements by Basin Electric.

- Sales of electricity to members - The delivery of energy under member wholesale power agreements is considered one single performance obligation as providing the electric power commodity and the transmission of the electricity is fulfilling a single promise to the customer. The terms of the wholesale power agreements specify the rate schedules applicable and other pricing provisions. The member rate schedules are approved by the Basin Electric Board of Directors. The satisfaction of the performance obligation is measured over time as the customer simultaneously receives and consumes the benefits provided. The output method is used where revenue is recognized based on the metered quantity and as energy is delivered.

BASIN ELECTRIC POWER COOPERATIVE AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS, Continued

- Sales of electricity to non-members - The sale of excess energy to non-members is considered a single performance obligation. The terms of either the bilateral power sales contract or the RTO market protocols determine the pricing terms. The satisfaction of the performance obligation is measured over time as the customer simultaneously receives and consumes the benefits provided. The output method is used where revenue is recognized as energy is delivered. Transactions are netted on an hourly basis and are recorded as either sales or purchases.
- Miscellaneous revenue - Miscellaneous revenue primarily consists of miscellaneous services provided and miscellaneous sales of equipment. Generally, a single performance obligation exists in the generation of other revenue and the performance obligation is satisfied at a point in time. The contract specifies the price, and revenue is recognized as delivery occurs or services are rendered.

Gasification operations mainly consists of the sale of synthetic natural gas, fertilizer and DEF products and other byproducts such as CO₂, tar oil and chemical products which are produced at Dakota Gas's Synfuels Plant.

- Synthetic natural gas and certain other byproducts - The sale and delivery of synthetic natural gas and certain other byproducts (exclusive of fertilizer and DEF products) is considered one single performance obligation as providing the commodity and the delivery of it is fulfilling a single promise to the customer as control transfers to the customer upon delivery. The performance obligation is satisfied at a point in time. The sales contracts specify the price, and revenue is recognized as delivery occurs.
- Fertilizer products - For the sale of fertilizer and DEF products, control transfers at a point in time depending on whether the shipping of the product is included in the performance obligation. The marketing agreement with N-7 specified the price and revenue was recognized as products exited the plant. After the dissolution of N-7, the price and revenue is recognized as control of the product transfers to the customer, which may be as products exit the plant or upon delivery, depending on the sales contract with these customers.
- Miscellaneous revenue - Miscellaneous revenue primarily consists of miscellaneous services provided and miscellaneous sales of equipment. Generally, a single performance obligation exists in the generation of other revenue and the performance obligation is satisfied at a point in time. The contract specifies the price, and revenue is recognized as delivery occurs or services are rendered.

Coal and limestone operations mainly consists of the sale of lignite coal that Dakota Coal purchases from Coteau from the Freedom Mine for use at AVS, LOS and Dakota Gas's Synfuels Plant.

- Lignite coal - The sale and delivery of lignite coal is considered one single performance obligation as providing the commodity and the delivery of it is fulfilling a single promise to the customer as control transfers to the customer upon delivery. The performance obligation is satisfied at a point in time. The coal supply contracts specify the price, and revenue is recognized as delivery occurs.
- Miscellaneous revenue - Miscellaneous revenue largely consists of sales of lime from Dakota Coal's lime plant and sales of limestone from MLC's limestone quarry and fine grind plant. The sale and delivery of lime and limestone is considered one single performance obligation as providing the lime and limestone and the delivery of it is fulfilling a single promise to the customer as control transfers to the customer upon delivery. The performance obligation is satisfied at a point in time. The sales contracts specify the price, and revenue is recognized as delivery occurs.

BASIN ELECTRIC POWER COOPERATIVE AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS, Continued

ACCOUNTS RECEIVABLE AND ALLOWANCE FOR CREDIT LOSSES—Accounts receivable primarily consists of wholesale electricity sales to members and non-members and sales of synthetic natural gas, fertilizer and DEF and other products. Accounts receivable are stated at billed and estimated unbilled amounts, net of allowance for credit losses.

An allowance for credit losses is recorded based on estimated uncollectible trade receivables. Estimated uncollectible trade receivables are reviewed with consideration given to historical experience, credit worthiness and the age of the receivable balances. An allowance for credit losses is recorded when we are aware of a customer's inability or reluctance to pay. Accounts are written off once they are determined to be uncollectible.

ACCOUNTING FOR GOVERNMENT GRANTS—As a part of the 45Q transaction to monetize Section 45Q tax credits, Dakota Gas received an initial payment of \$167.5 million in 2024 from the tax equity investor and the right to receive installment payments in exchange for certain membership interest in DCS. The initial payment was recognized in other noncurrent liabilities and the initial payment is accounted for as a sale of future revenue using the effective interest method. The carrying amount of the initial payment liability is the present value of the expected future tax credits to be earned. When there is reasonable assurance that the tax credits will be earned, the initial payment liability is reduced and other income with an interest expense component is recorded. The installment payments are recorded as other income when received.

Dakota Gas accounts for the monetization of the tax credits that DCS is eligible to receive under Section 45Q of the U.S. IRC as government grants under the grant model by analogy to IFRS (International Financial Reporting Standards) IAS (International Accounting Standards) 20, Accounting for Government Grants and Disclosure of Government Assistance. The Section 45Q tax credits are considered a grant related to income and Basin Electric has elected to present the monetization of the benefit as other and tax credits income and interest expense on the consolidated statements of operations. The monetization of the Section 45Q tax credits are recognized when there is reasonable assurance that the tax credits will be received.

LEASES—Leases are classified as either operating leases or finance leases based on guidance provided in ASC 842, *Leases*. Lease liabilities and their corresponding lease assets are recorded based on the present value of lease payments over the expected lease term. Lease expense for minimum lease payments is recognized on a straight-line basis over the lease term for operating leases. For finance leases, the amortization of lease assets is recognized on a straight-line basis. Basin Electric does not recognize a corresponding lease asset or lease liability for leases with an original lease term of 12 months or less. Basin Electric determines the lease term based on the non-cancelable period in each contract, as well as any cancelable periods for which it is reasonably certain the lease will be extended.

The discount rate used to calculate the present value of the lease liabilities is based upon the implied rate within each contract. If the rate is unknown or cannot be determined, Basin Electric uses an incremental borrowing rate, which is determined by the length of the contract and Basin Electric's estimated borrowing rates as of the commencement date of the contract.

Variable lease payments that do not depend on an index or rate are recognized as incurred.

PROPERTY, PLANT AND EQUIPMENT—Property, plant and equipment are stated at cost, including contract work, direct labor and materials, allocable overheads and allowance for funds used during construction. Repairs and maintenance are charged to operations as incurred. Generally, when electric plant is retired, sold, or otherwise disposed of, the original cost plus the cost of removal less salvage value is charged to accumulated depreciation and the corresponding gain or loss is amortized over the remaining life of the plant. However, when an entire electric plant unit or system or land is sold, the cost

BASIN ELECTRIC POWER COOPERATIVE AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS, Continued

and the related accumulated depreciation are eliminated and a gain or loss is reflected in the consolidated statements of operations. When nonutility property is retired or sold any gain or loss is reflected in the consolidated statements of operations. For more information, see Note 5.

DEPRECIATION, DEPLETION AND AMORTIZATION—Electric plant and nonutility property at Dakota Gas is depreciated using a straight-line method over a remaining estimated useful life. For nonutility property at Dakota Coal, depreciation and depletion are provided for using the straight-line method based on the estimated useful lives or the units-of-production method based on estimated recoverable tonnage. For more information, see Note 5.

RECOVERABILITY OF LONG-LIVED ASSETS—Basin Electric accounts for the impairment or disposal of long-lived assets in accordance with ASC 360, Property, Plant, and Equipment, which requires long-lived assets, such as property and equipment, to be evaluated for impairment whenever events or changes in circumstances indicate the carrying value of an asset may not be recoverable. An impairment has occurred when estimated undiscounted cash flows expected to result from the use of the asset plus net proceeds expected from disposition of the asset, if any, are less than the carrying value of the asset. If an impairment has occurred, the carrying amount of the asset is reduced to its estimated fair value based on quoted market prices or other valuation techniques.

The impairment loss of \$4.2 million in 2025 relates to coal gasification additions that were impaired upon purchase. The impairment loss of \$36.3 million in 2024 consists of \$32.3 million related to NRG's investment in NTEC; as it is not expected to generate any future cash flows, and \$4.0 million of coal gasification additions that were impaired upon purchase. In 2018, management determined that certain coal gasification assets were impaired, consequently any subsequent coal gasification asset additions were impaired upon purchase.

An impairment loss of \$5.0 million in 2023 consists of coal gasification additions that were impaired upon purchase.

REGULATORY ASSETS AND LIABILITIES—Basin Electric is subject to the provisions of ASC 980. Regulatory assets represent probable future revenue to Basin Electric associated with certain costs which will be recovered from customers through the ratemaking process. Regulatory liabilities represent probable future reductions in revenue associated with amounts that are to be credited to customers through the ratemaking process. For more information, see Note 9.

INCOME TAXES—Basin Electric uses the asset and liability method to account for income taxes. Under this method, deferred tax assets and liabilities are recognized for the expected future tax consequences of all temporary differences between the carrying amounts of assets and liabilities and their respective tax bases. Deferred taxes are recorded using the tax rates scheduled by tax law to be in effect in the periods when the temporary differences reverse. Deferred tax assets are reduced by a valuation allowance when it is more likely than not that a portion or all of the deferred tax assets will not be realized. The realizability of deferred tax assets is determined by taking into consideration forecasts of future taxable income, the reversal of other existing temporary differences, available net operating loss carryforwards and available tax planning strategies. Changes in valuation allowances are included in the provision for income taxes in the period of the changes.

Basin Electric recognizes the tax effects of all tax positions that are more-likely-than-not to be sustained on audit based solely on the technical merits of those positions as of the balance sheet date. Changes in the recognition or measurement of such positions are recognized in the provision for income taxes in the period of the changes. Basin Electric classifies interest and penalties on tax uncertainties as components of those accounts in the consolidated statements of operations. For more information, see Note 13.

BASIN ELECTRIC POWER COOPERATIVE AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS, Continued

DERIVATIVE FINANCIAL INSTRUMENTS-All derivatives are measured at fair value and recognized as either assets or liabilities on the consolidated balance sheets, except for derivative contracts that qualify for and are elected under the normal purchase and normal sales exception under the requirements of ASC 815, Derivatives and Hedging. Basin Electric, Dakota Gas and Dakota Coal evaluate all purchase and sale contracts when executed to determine if they are derivatives and, if so, if they meet the normal purchase normal sale exception requirements under ASC 815. The derivative instruments that do not meet the normal purchase and normal sales exception are evaluated for designation as cash flow hedges of forecasted sales and purchases of commodities. Basin Electric also utilizes interest rate swap agreements to reduce exposure to interest rate fluctuations associated with floating rate debt obligations and anticipated debt financing.

Under ASC 980, Basin Electric defers changes in the fair value of certain derivative activity as a regulatory item to be recovered through rates in the future. Only current settlements of these derivative transactions are included in earnings. For more information, see Note 8.

COLLATERAL-Certain derivative instruments and certain agreements of Basin Electric and Dakota Gas contain contract provisions that require collateral to be posted if the credit ratings of Basin Electric fall below certain levels or if the counterparty exposure to Basin Electric or Dakota Gas exceeds a certain level.

Collateral posted (received) is related to derivative assets and liabilities and agreements that contain credit-related contingent features and is included in the consolidated balance sheets as follows:

	2025	2024
	(In thousands)	
Other investments	\$ 47,575	\$ 50,633
Cash and cash equivalents	-	1,297
Prepayments and other current assets	3,350	6,530
Other current liabilities	(1,954)	(3,311)
	<u>\$ 48,971</u>	<u>\$ 55,149</u>

ASSETS AND LIABILITIES MEASURED AT FAIR VALUE-ASC 820, Fair Value Measurements, defines fair value, establishes a framework for measuring fair value, and expands disclosures about fair value measurements. The standard applies to reported balances that are required or permitted to be measured at fair value.

ASC 820 emphasizes that fair value is a market-based measurement, not an entity-specific measurement. Therefore, a fair value measurement should be determined based on the assumptions that market participants would use in pricing the asset or liability. As a basis for considering market participant assumptions in fair value measurements, ASC 820 establishes a fair value hierarchy that distinguishes between market participant assumptions based on market data obtained from sources independent of the reporting entity (observable inputs that are classified within Levels 1 and 2 of the hierarchy) and the reporting entity's own assumptions about market participant assumptions (unobservable inputs classified within Level 3 of the hierarchy). For more information, see Note 14.

INSURANCE PROCEEDS- In 2022, Dakota Gas had an electrical power outage loss that resulted in reduced equipment availability. As a result of that event, in 2023, Dakota Gas and Dakota Coal received \$26.6 million of business interruption insurance proceeds. In 2024, due to the same event Dakota Gas received \$8.5 million of property damage insurance proceeds. The insurance proceeds were recognized as a reduction of nonelectric selling, general and administrative expenses in the consolidated statements of operations.

BASIN ELECTRIC POWER COOPERATIVE AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS, Continued

In 2022, Dakota Gas had a fire resulting in the loss of property. As a result of that event, in 2024, Dakota Gas settled with its insurance carrier on the claim resulting in recognition of \$13.8 million of property damage insurance proceeds. The property damage insurance proceeds were recognized as a reduction of nonelectric selling, general and administrative expenses in the consolidated statements of operations.

SUBSEQUENT EVENTS—Basin Electric considered events for recognition or disclosure in the consolidated financial statements that occurred subsequent to December 31, 2025 through April 15, 2026, the date the consolidated financial statements were available for issuance.

Management is not aware of any material subsequent events that would require recognition or disclosure in the 2025 consolidated financial statements.

3. NEW ACCOUNTING PRONOUNCEMENTS

RECENTLY ADOPTED ACCOUNTING STANDARD UPDATES (ASU)

ASU 2023-09, Income Taxes: Improvements to Income Tax Disclosures – In December 2023, the FASB issued new guidance to improve the transparency of income tax disclosures related to the rate reconciliation and income taxes paid disclosures. Other amendments improve the effectiveness and comparability of disclosures by adding disclosures of pretax income (or loss) and income tax expense (or benefit) and removing disclosures that no longer are considered cost beneficial or relevant. Basin Electric has retrospectively implemented this guidance for the year ended December 31, 2025 and has identified and updated disclosures to ensure compliance with the new guidance, which are included in Note 13.

RECENTLY ISSUED ACCOUNTING STANDARD UPDATES NOT YET ADOPTED

ASU No. 2024-03, Income Statement-Reporting Comprehensive Income-Expense Disaggregation Disclosures: Disaggregation of Income Statement Expenses – In November 2024, the FASB issued new guidance to improve disclosures about a public business entity's expenses that will require additional detail for certain categories of income statement expenses. The new guidance will be effective for Basin Electric for annual reporting periods beginning after December 15, 2026, and interim reporting periods beginning after December 15, 2027. Early adoption is permitted and the new guidance is to be applied either on a prospective or retrospective basis. Management is currently evaluating the impact of adoption of this new guidance on the financial statements and disclosures.

ASU No. 2025-05, Financial Instruments-Credit Losses: Measurement of Credit Losses for Accounts Receivable and Contract Assets – In July 2025, the FASB issued new guidance to address challenges encountered when applying existing guidance to current accounts receivable and current contract assets arising from transactions accounted for under Topic 606, Revenue from Contracts with Customers. The amendments in this update introduce a practical expedient for all entities and an accounting policy election for entities other than public business entities. The new guidance will be effective for Basin Electric for annual reporting periods beginning after December 15, 2025, and interim reporting periods within those annual reporting periods. Early adoption is permitted and the new guidance is to be applied on a prospective basis. Management is currently evaluating the impact of adoption of this new guidance on the financial statements and disclosures.

ASU No. 2025-06, Intangibles-Goodwill and Other-Internal-Use Software: Targeted Improvements to the Accounting for Internal-Use Software – In September 2025, the FASB issued new guidance to modernize existing older guidance regarding capitalization and recognition to reflect the software development approaches currently being utilized. The new guidance will be effective for Basin Electric for annual reporting periods beginning after December 15, 2027, and interim reporting periods within those annual reporting periods. Early adoption is permitted and the new guidance is to be applied using one of

BASIN ELECTRIC POWER COOPERATIVE AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS, Continued

the three prescribed approaches. Management is currently evaluating the impact of adoption of this new guidance on the financial statements and disclosures.

ASU No. 2025-09, Derivatives and Hedging: Hedge Accounting Improvements – In November 2025, the FASB issued new guidance in an effort to better reflect an entity's risk management activities in the financial statements. The update makes targeted improvements by addressing five specific matters that arose from the implementation of previous ASU 2017-12, *Derivatives and Hedging: Targeted Improvements for Accounting for Hedging Activities* and the effects of LIBOR cessation. The new guidance will be effective for Basin Electric for annual reporting periods beginning after December 15, 2026, and interim reporting periods within those annual reporting periods. Early adoption is permitted and the new guidance is to be applied on a prospective basis, although an entity may elect to adopt the guidance for hedging relationships that exist as of the date of adoption. Management is currently evaluating the impact of adoption of this new guidance on the financial statements and disclosures.

ASU No. 2025-10, Government Grants: Accounting for Government Grants Received by Business Entities – In December 2025, the FASB issued new guidance to improve GAAP by establishing authoritative guidance on the accounting for government grants received by business entities. Previously, GAAP did not provide specific guidance about the recognition, measurement, and presentation of a grant received by a business entity from a government, and due to this absence of specific guidance, Basin Electric like many other business entities, utilized the guidance contained in IAS 20, *Accounting for Government Grants and Disclosure of Government Assistance*. The new guidance will be effective for Basin Electric for annual reporting periods beginning after December 15, 2028, and interim reporting periods within those annual reporting periods. Early adoption is permitted and the new guidance is to be applied using one of the three prescribed approaches. Management is currently evaluating the impact of adoption of this new guidance on the financial statements and disclosures.

4. LEASES

LESSEE ACCOUNTING—Most of the leases Basin Electric enters into are for certain substation, office and communication equipment, mining equipment, railcars, certain land leases and a generation facility, as part of its ongoing operations. Basin Electric determines if an arrangement contains a lease at inception of a contract.

Generally, the leases for certain substation, office and communication equipment, mining equipment and railcars have a term of ten years or less, certain land leases have a longer term of up to 100 years and the generation facility has a term of ten years. To date, Basin Electric does not have any residual value guarantee amounts probable of being owed to a lessor. Basin Electric does have financing leases and material agreements with related parties.

The lease costs are included in electric operations and maintenance, cost of products sold, nonelectric selling, general and administrative expenses, depreciation and amortization and interest expense on the consolidated statements of operations.

BASIN ELECTRIC POWER COOPERATIVE AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS, Continued

The components of lease expense for the years ended December 31 were as follows:

	2025	2024	2023
	(In thousands)		
Finance lease cost:			
Amortization of lease assets	\$ 1,533	\$ 1,674	\$ 1,228
Interest on lease liabilities	428	503	435
Operating lease cost	33,885	26,330	25,502
Short-term lease cost	2,583	2,114	4,478
Variable lease cost	1,267	1,309	1,062
Sublease income	(1,657)	(1,562)	(1,541)
Total lease cost	\$ 38,039	\$ 30,368	\$ 31,164

Supplemental cash flow information related to leases as of December 31 was as follows:

	2025	2024	2023
	(In thousands)		
Cash paid for amounts included in the measurement of lease liabilities:			
Operating cash flows from finance leases	\$ 180	\$ 243	\$ 286
Operating cash flows from operating leases	\$ 32,669	\$ 25,909	\$ 25,848
Financing cash flows from finance leases	\$ 1,217	\$ 1,138	\$ 810

BASIN ELECTRIC POWER COOPERATIVE AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS, Continued

Supplemental balance sheet information related to leases as of December 31 was as follows:

	Balance Sheet Location	2025	2024
(In thousands)			
Assets:			
Net operating lease assets	Other deferred charges	\$ 129,903	\$ 124,062
Financing lease assets	Plant in service	\$ 11,911	\$ 12,522
Less: Accumulated amortization	Accumulated provision for depreciation and amortization	(4,824)	(4,274)
Net finance lease assets		\$ 7,087	\$ 8,248
Liabilities:			
Current:			
Operating leases	Other current liabilities	\$ 30,030	\$ 22,434
Finance leases	Long-term debt and finance leases due within one year	1,114	1,066
Total current lease liabilities		\$ 31,144	\$ 23,500
Noncurrent:			
Operating leases	Other noncurrent liabilities	\$ 99,987	\$ 101,773
Finance leases	Finance lease obligations	3,532	4,305
Total noncurrent lease liabilities		\$ 103,519	\$ 106,078

Weighted average remaining terms and discount rates related to leases as of December 31 was as follows:

	2025	2024
Weighted-average remaining lease term-finance leases	10.9 years	10.9 years
Weighted-average remaining lease term-operating leases	9.6 years	10.9 years
Weighted-average discount rate-finance leases	5.1 %	5.3 %
Weighted-average discount rate-operating leases	4.6 %	3.7 %

BASIN ELECTRIC POWER COOPERATIVE AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS, Continued

The reconciliation of the future undiscounted cash flows to the lease liabilities presented on the consolidated balance sheet at December 31, 2025, was as follows:

Year	Operating Leases	Finance Leases	Total
		(In thousands)	
2026	\$ 31,661	\$ 1,364	\$ 33,025
2027	31,539	865	32,404
2028	20,304	598	20,902
2029	15,123	359	15,482
2030	13,716	206	13,922
Thereafter	47,319	2,919	50,238
Total lease payment	159,662	6,311	165,973
Less: discount	29,645	1,665	31,310
Total lease liabilities	<u>\$ 130,017</u>	<u>\$ 4,646</u>	<u>\$ 134,663</u>

BASIN ELECTRIC POWER COOPERATIVE AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS, Continued

5. PROPERTY, PLANT AND EQUIPMENT AND JOINTLY OWNED FACILITIES

Significant components of property, plant and equipment were as follows at December 31:

	Depreciable Lives	2025	2024
(In thousands)			
Electric Utility:			
Generation	20-60 years	\$ 6,549,352	\$ 5,811,843
Transmission	20-60 years	1,606,477	1,569,678
General plant	3-20 years	352,711	327,392
Other property	3-32 years	1,909	1,909
Construction work in progress		769,953	819,808
Total Electric Utility		9,280,402	8,530,630
Less: accumulated provision for depreciation and amortization		(3,602,271)	(3,449,655)
		<u>5,678,131</u>	<u>5,080,975</u>
Gasification:			
Synfuels Plant	30 years	917,633	905,983
Pipelines	2-30 years	64,069	64,069
Other property	3-30 years	111,170	113,542
Construction work in progress		8,568	4,872
Total Gasification		1,101,440	1,088,466
Less: accumulated provision for depreciation and amortization		(404,633)	(372,288)
		<u>696,807</u>	<u>716,178</u>
Coal and Limestone Operations:			
Mining	10-20 years	584,895	537,343
Lime and limestone	10-20 years	50,364	50,477
Other property	3-20 years	12,286	13,706
Construction work in progress		242	7,092
Total Coal and Limestone Operations		647,787	608,618
Less: accumulated provision for depreciation, depletion and amortization		(369,013)	(347,058)
		<u>278,774</u>	<u>261,560</u>
Other:			
Other property	3-32 years	1,907	1,907
Total Other		1,907	1,907
Total net property, plant and equipment		\$ 6,655,619	\$ 6,060,620

Construction work in progress included \$27.9 million and \$33.8 million as of December 31, 2025 and 2024, respectively, of interest charged and capitalized to construction. Annual depreciation, depletion and amortization expense totaled \$287.2 million, \$269.9 million and \$260.1 million for 2025, 2024 and 2023, respectively.

BASIN ELECTRIC POWER COOPERATIVE AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS, Continued

Basin Electric's investment in the jointly owned MBPP electric plant included in Electric Utility property above was as follows at December 31:

	2025	2024
	(In thousands)	
Electric plant	\$ 970,637	\$ 965,675
Less: accumulated provision for depreciation and amortization	(648,917)	(627,848)
	\$ 321,720	\$ 337,827

6. RESTRICTED AND DESIGNATED CASH AND INVESTMENTS

Cash, cash equivalents, and restricted and designated cash and cash equivalents reported within the consolidated balance sheets and included in the consolidated statement of cash flows are as follows at December 31:

	2025	2024
	(In thousands)	
Cash and cash equivalents	\$ 685,570	\$ 376,659
Restricted and designated cash and equivalents:		
MBPP operating funds	29,923	27,251
Deferred revenue funds	272,000	290,000
	301,923	317,251
Total cash, cash equivalents and restricted and designated cash and equivalents included in the consolidated statements of cash flows	\$ 987,493	\$ 693,910

Restricted and designated investments reported within the consolidated balance sheets are as follows at December 31:

	2025	2024
	(In thousands)	
Restricted and designated investments:		
Funds held in trust for an asset retirement obligation by Bank of Montreal as trustee for SVPL	5,244	4,550
Asset retirement obligations	56,118	49,763
	\$ 61,362	\$ 54,313

Restricted cash and investments include funds held by a financial institution, as trustee, at December 31. Designated cash and investments includes amounts designated by the Basin Electric Board of Directors.

BASIN ELECTRIC POWER COOPERATIVE AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS, Continued

7. INVESTMENTS

Investments in equity securities and available-for-sale debt securities are included in mine related assets, restricted and designated investments and other investments on the consolidated balance sheets. The cost, unrealized holding gains and losses, and fair value of equity and debt securities that do not have an allowance for credit losses were as follows as of December 31, 2025:

	Cost	Gross Unrealized Holding		Fair Value
		Gains	Losses	
(In thousands)				
Available-for-sale debt securities:				
Corporate and government bonds	\$ 1,947	\$ 24	\$ -	\$ 1,971
Equity securities:				
Equities and equity funds	42,147	86,512	-	128,659
Bond market funds	78,577	-	(5,573)	73,004
	120,724	86,512	(5,573)	201,663
Other	88	-	-	88
	<u>\$ 122,759</u>	<u>\$ 86,536</u>	<u>\$ (5,573)</u>	<u>\$ 203,722</u>

During 2025, sales proceeds on debt securities classified as available-for-sale were \$143.9 million. The cost of securities sold is based on the specific identification method.

The cost, unrealized holding gains and losses, and fair value of equity and debt securities that do not have an allowance for credit losses were as follows as of December 31, 2024:

	Cost	Gross Unrealized Holding		Fair Value
		Gains	Losses	
(In thousands)				
Available-for-sale debt securities:				
Corporate and government bonds	\$ 117,064	\$ 83	\$ (54)	\$ 117,093
Equity securities:				
Equities and equity funds	43,766	76,830	-	120,596
Bond market funds	65,044	-	(7,462)	57,582
	108,810	76,830	(7,462)	178,178
Other	28	-	-	28
	<u>\$ 225,902</u>	<u>\$ 76,913</u>	<u>\$ (7,516)</u>	<u>\$ 295,299</u>

During 2024, sales proceeds on debt securities classified as available-for-sale were \$91.2 million. The cost of securities sold is based on the specific identification method.

BASIN ELECTRIC POWER COOPERATIVE AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS, Continued

The fair value of available-for-sale debt securities by contracted maturity date as of December 31 was as follows:

	<u>2025</u>
	<u>(In thousands)</u>
Due through one year	\$ 458
Due after one year through five years	720
Due after five years	793
	<u>\$ 1,971</u>

Held-to-maturity debt securities have contracted maturity dates of one year or less and are included in Cash and cash equivalents, Restricted and designated cash and cash equivalents and short-term investments on the consolidated balance sheets. The amortized costs were as follows for the years ended December 31:

	<u>2025</u>	<u>2024</u>
	<u>(In thousands)</u>	
Corporate commercial paper	\$ 38,030	\$ 38,938
Money market funds	745,170	448,162
Treasuries	199,300	212,727
	<u>\$ 982,500</u>	<u>\$ 699,827</u>

Included in other investments on the consolidated balance sheets is the cash surrender value of life insurance policies of \$1.6 million and \$1.8 million, as of December 31, 2025 and 2024, respectively.

The MBPP provides financing to Western Fuels Association (Western Fuels) and Western Fuels-Wyoming, Inc. (WFW), a wholly owned subsidiary of Western Fuels, for mine development costs associated with coal deliveries to LRS. Basin Electric provides financing to Western Fuels and WFW for mine development costs associated with coal deliveries to DFS.

Notes receivable from WFW of \$20.8 million and \$21.5 million as of December 31, 2025 and 2024, respectively, are included in other investments, investments in associated companies and receivables, net on the consolidated balance sheets. Maturities range from July 2026 through May 2043, and the weighted average interest rate is 5.54 percent. The estimated fair value of these notes receivable as of December 31, 2025 and 2024 was \$21.0 million and \$20.9 million, respectively, based on the future cash flows discounted using the yield on a treasury note with a similar maturity.

BASIN ELECTRIC POWER COOPERATIVE AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS, Continued

8. DERIVATIVE FINANCIAL INSTRUMENTS

Normal operations expose Basin Electric to risks associated with changes in the market price of certain commodities. Basin Electric entered into derivative financial instruments for the purpose of mitigating the risks associated with market price volatility of natural gas, tar oil, electricity and diesel. Any changes in cash flows from the underlying purchases and sales that are indexed to certain prices are offset by corresponding changes in the cash flows from the derivatives. As directed by a Basin Electric Board of Director's policy (Board Policy) to monitor risk and establish an internal control framework, Basin Electric maintains a Risk Management Steering Committee (RMSC) that is governed by a Commodity Risk Management Manual (Manual). The Board Policy prohibits speculation and the Manual has been adopted by the RMSC. In offsetting market risk, Basin Electric is exposed to other forms of incremental risk such as credit or liquidity risk.

The following table presents the outstanding hedged forecasted transactions as of December 31, 2025:

Hedged Transaction	Term	Contracted Monthly Volumes of Forecasted Transactions	Price
Natural gas sales	Through February 2026	6%	\$6.32 per dekatherm
Natural gas purchases	Through December 2033	16% to 87%	\$2.79 - \$6.51 per dekatherm
Tar oil sales	Through November 2027	29% to 83%	\$52.00 - \$62.95 per barrel
Electricity purchases	Through December 2027	13% to 100%	\$30.50 - \$58.60 per MWh
Diesel purchases	Through December 2028	25% to 89%	\$2.07 - \$2.44 per gallon

Basin Electric is also exposed to interest rate risk. To mitigate this risk, Basin Electric entered into various interest rate swap agreements to reduce the impact of changes in interest rates on certain variable rate long-term bonds. The following table presents the outstanding swap agreements on variable rate bonds as of December 31, 2025:

Notional Amount (In thousands)	Due	Effective Interest Rate
\$ 100,000	2032	6.18 %
\$ 50,000	2032	4.95 %
\$ 50,000	2030	5.33 %

BASIN ELECTRIC POWER COOPERATIVE AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS, Continued

The fair value and classification of the asset and liability portion of the derivative instruments in the consolidated balance sheets is as follows as of December 31:

Balance Sheet Location	2025		2024	
	Fair Value of Asset Derivatives	Fair Value of Liability Derivatives	Fair Value of Asset Derivatives	Fair Value of Liability Derivatives
(In thousands)				
Derivatives designated as cash flow hedges:				
Commodity derivatives:				
Prepayments and other current assets	\$ 5,312	\$ -	\$ 683	\$ -
Other investments	1,684	-	745	-
Other current liabilities	-	(1,319)	-	(1,092)
Other noncurrent liabilities	-	(671)	-	(1,006)
Total derivatives designated as cash flow hedges	\$ 6,996	\$ (1,990)	\$ 1,428	\$ (2,098)
Derivatives not designated as cash flow hedges:				
Commodity derivatives:				
Prepayments and other current assets	\$ 34,673	\$ -	\$ 32,291	\$ -
Other investments	1,211	-	841	-
Other current liabilities	-	(14,763)	-	(10,298)
Other noncurrent liabilities	-	(14,687)	-	(6,507)
Interest rate derivatives:				
Other noncurrent liabilities	-	(22,031)	-	(18,351)
Total derivatives not designated as cash flow hedges	\$ 35,884	\$ (51,481)	\$ 33,132	\$ (35,156)
	<u>\$ 42,880</u>	<u>\$ (53,471)</u>	<u>\$ 34,560</u>	<u>\$ (37,254)</u>

Under ASC 980, Basin Electric defers changes in the fair value of certain derivative instruments as regulatory assets or liabilities. Current settlements of derivatives, including interest rate swaps and commodity derivatives, resulted in charges to the consolidated statements of operations for the years ended December 31, 2025, 2024 and 2023 of \$6.6 million, \$61.0 million, and \$84.2 million, respectively, which are reclassified from regulatory assets and liabilities.

The change in fair value of derivatives deferred as a regulatory item for the years ended December 31, 2025, 2024 and 2023 resulted in net deferred losses of \$21.7 million, \$10.7 million and \$63.8 million, respectively.

For derivative instruments that are designated and qualify as a cash flow hedge under ASC 815, the gain or loss on the derivative instrument is reported as a component of other comprehensive income (loss) and reclassified into net earnings in the same period or periods during which the hedged transaction affects net margin and earnings and is presented in the same line item on the consolidated statements of operations as the net earnings effect of the hedged item.

BASIN ELECTRIC POWER COOPERATIVE AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS, Continued

The following table summarizes Dakota Gas and Dakota Coal gains and losses and financial statement classification of the derivatives designated as cash flow hedges as of December 31, 2025. This does not reflect the expected gains or losses arising from the underlying physical transactions; therefore it is not indicative of the economic gross profit or loss realized when the underlying physical and financial transactions were settled.

	Location of Gain (Loss) Recognized in Net Loss on Cash Flow Hedging Relationships	
	2025	
	Other Operating Revenues	Cost of Products Sold
	(In thousands)	
Total amounts of income and expense line items presented on the consolidated statements of operations in which the effects of cash flow hedges are recorded	\$ 925,715	\$ 597,232
Gain (loss) on cash flow hedges:		
Commodity derivatives:		
Amount reclassified from accumulated other comprehensive income into net margins and earnings	\$ 1,982	\$ (681)

The following table summarizes Dakota Gas and Dakota Coal gains and losses and financial statement classification of the derivatives designated as cash flow hedges as of December 31, 2024.

	Location of Gain (Loss) Recognized in Net Loss on Cash Flow Hedging Relationships	
	2024	
	Other Operating Revenues	Cost of Products Sold
	(In thousands)	
Total amounts of income and expense line items presented on the consolidated statements of operations in which the effects of cash flow hedges are recorded	\$ 819,440	\$ 542,295
Gain (loss) on cash flow hedges:		
Commodity derivatives:		
Amount reclassified from accumulated other comprehensive income into net margins and earnings	\$ 3,809	\$ (950)

BASIN ELECTRIC POWER COOPERATIVE AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS, Continued

The following table summarizes Dakota Gas and Dakota Coal gains and losses and financial statement classification of the derivatives designated as cash flow hedges as of December 31, 2023.

	Location of Gain Recognized in Net Loss on Cash Flow Hedging Relationships	
	2023	
	Other Operating Revenues	Cost of Products Sold
	(In thousands)	
Total amounts of income and expense line items presented on the consolidated statements of operations in which the effects of cash flow hedges are recorded	960,904	544,439
Gain on cash flow hedges:		
Commodity derivatives:		
Amount reclassified from accumulated other comprehensive income into net margins and earnings	\$ 29,410	\$ 767

The following table summarizes the gains and losses arising from hedging transactions that were recognized as a component of other comprehensive income (loss) for the years ended December 31.

	2025	2024	2023
	(In thousands)		
Increase (decrease) in fair value of commodity derivatives ..	\$ 6,976	\$ (3,264)	\$ 17,387
Recognition of gains in earnings due to settlements on commodity derivatives	(1,301)	(2,859)	(30,177)
Total other comprehensive income (loss) from hedging	<u>\$ 5,675</u>	<u>\$ (6,123)</u>	<u>\$ (12,790)</u>

Based on December 31, 2025 prices, a \$4.0 million gain would be realized, reported in pre-tax earnings and reclassified from Accumulated other comprehensive income during the next 12 months. As market prices fluctuate, estimated and actual realized gains or losses will change during future periods.

There are certain commodity derivative financial instruments that do not meet the criteria for hedge accounting under ASC 815 when using the critical terms match effectiveness assessment. For those derivatives, gains or losses are recorded in the consolidated statements of operations. The following table summarizes the impact of commodity derivatives that do not meet the criteria. This does not reflect the expected gains or losses arising from the underlying physical transactions; therefore it is not indicative of the economic gross profit or loss realized when the underlying physical and financial transactions were settled.

Location of Gain (Loss) on Derivatives Recognized in Net Margin and Earnings	2025	2024	2023
	Recognized Loss	Recognized Loss	Recognized Gain (Loss)
	(In thousands)		
Derivatives not designated as cash flow hedges:			
Commodity derivatives:			
Operating revenues	\$ (432)	\$ (2,042)	\$ (1,924)
Operating revenues	-	-	612
Total	<u>\$ (432)</u>	<u>\$ (2,042)</u>	<u>\$ (1,312)</u>

BASIN ELECTRIC POWER COOPERATIVE AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS, Continued

9. REGULATORY ASSETS AND LIABILITIES

Regulatory assets and liabilities were as follows as of December 31:

	Remaining Recovery Period	2025	2024
(In thousands)			
Regulatory assets:			
Deferred income taxes	Over Plant lives	\$ 160,754	\$ 155,660
Refinancing fees	Up to 24 years	80,122	86,297
Unrealized loss on interest rate swaps	Up to 7 years	21,066	17,385
Unrealized loss on commodity derivatives	Up to 8 years	28,239	10,283
Other	Up to 50 years	21,192	25,532
		<u>\$ 311,373</u>	<u>\$ 295,157</u>
Regulatory liabilities:			
Deferred revenue		(272,000)	(290,000)
Unrealized gain on purchase power contracts		-	(100)
Unrealized gain on equity investments		(18,489)	(15,696)
Post-retirement medical gain		(21,044)	(16,389)
Other		(24,772)	(15,056)
		<u>(336,305)</u>	<u>(337,241)</u>
Net regulatory liabilities		<u><u>\$ (24,932)</u></u>	<u><u>\$ (42,084)</u></u>

If all or a separable portion of Basin Electric's operations no longer are subject to the provisions of ASC 980, a write-off of net related regulatory assets (liabilities) would be required, unless some form of transition recovery (refund) continues through rates established and collected for Basin Electric's remaining regulated operations. In addition, Basin Electric would be required to determine any impairment to the carrying costs of deregulated plant and inventory assets.

BASIN ELECTRIC POWER COOPERATIVE AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS, Continued

10. EQUITY

ACCUMULATED OTHER COMPREHENSIVE INCOME—The following table includes the changes in the balances of the components of accumulated other comprehensive income on the consolidated balance sheets:

	Post Employment Benefit Plans	Unrealized Gain (Loss) on Securities	Unrealized Gain (Loss) on Cash Flow Hedges	Total
	(In thousands)			
Balance, December 31, 2022	(1,525)	(3,813)	14,413	9,075
Comprehensive income (loss)	4,010	2,756	(10,103)	(3,337)
Balance, December 31, 2023	2,485	(1,057)	4,310	5,738
Comprehensive income (loss)	2,826	1,079	(4,837)	(932)
Balance, December 31, 2024	5,311	22	(527)	4,806
Comprehensive income (loss)	4,180	(6)	4,483	8,657
Balance, December 31, 2025	\$ 9,491	\$ 16	\$ 3,956	\$ 13,463

OTHER EQUITY—From November 1981 through August 1983, Basin Electric sold approximately \$894.0 million of electric plant under sale and leaseback agreements in exchange for \$310.0 million in cash and \$584.0 million in notes. Annual lease payments are equal to the payments the purchaser is required to make on its notes to Basin Electric. The sale and lease transactions have not been recognized for financial reporting purposes, as such transactions were entered into solely for tax purposes under the Economic Recovery Tax Act of 1981 and the Tax Equity and Fiscal Responsibility Act of 1982 and do not affect Basin Electric's rights with respect to the property. The \$310.0 million, net of expenses of \$28.0 million, was reserved in other equity.

Beginning in March 2001, Basin Electric allocated its before tax margin to members and recorded any provision for or benefit from income taxes in other equity. In 2025, 2024, and 2023, net income tax (benefit) expense of \$(9.1) million, \$1.3 million and \$59.9 million, respectively, was closed into other equity. As of December 31, 2025, \$21.0 million of cumulative net income tax benefit was closed into other equity.

BASIN ELECTRIC POWER COOPERATIVE AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS, Continued

11. LONG-TERM DEBT AND OTHER FINANCING

Outstanding long-term debt was as follows as of December 31:

	<u>Due Date</u>	<u>Weighted Average Interest Rate at December 31, 2025</u>	<u>2025</u>	<u>2024</u>
(In thousands)				
Basin Electric Power Cooperative				
First Mortgage Bonds				
2006 Series	June 2041	6.13%	\$ 200,000	\$ 200,000
2017 Series	April 2047	4.75%	500,000	500,000
2025 Series	Oct. 2055	5.85%	700,000	-
			<u>1,400,000</u>	<u>700,000</u>
First Mortgage Obligations				
2005 Series	Dec. 2028-May 2030	5.85%	90,000	90,000
2007 Series	Sep. 2042	5.74%	216,854	225,216
2008 Series	Dec. 2028-Dec. 2038	5.98%	413,389	429,333
2009 Series	Oct. 2027-April 2040	5.47%	132,222	143,333
2011 Series	Oct. 2031-Oct. 2049	4.53%	208,080	223,745
2012 Series	Nov. 2044	4.07%	73,949	76,489
2015 Series	June 2027-June 2044	4.50%	1,353,420	1,427,590
2016 CoBank Note	April 2046	4.48%	68,333	71,667
2016 CFC Note	April 2046	3.74%	51,050	53,571
2022 Series	Feb. 2042-Feb. 2062	3.00%	276,810	276,810
2024 CoBank Note	Nov. 2034- May 2035	6.14%	200,000	100,000
2024 Series	Feb. 2029-Feb. 2054	6.22%	350,525	363,508
2007 and 2008 Notes	June 2027-Dec. 2028	5.09%	4,750	6,750
2023 Note	Oct. 2043	5.56%	72,000	76,000
2025 RUS Loan	June 2033	4.33%	538	-
			<u>3,511,920</u>	<u>3,564,012</u>
Equipment Notes	Dec. 2035- Mar. 2026	5.09%	21,617	9,600
2019 Tax-Exempt Bonds	July 2039	3.63%	150,000	150,000
Notes payable to affiliates			-	4,400
			<u>171,617</u>	<u>164,000</u>
Dakota Coal				
Equipment Notes	Jan. 2026-July 2036	4.91%	66,462	78,523
Dakota Gasification Company				
Senior Secured Notes 2015 Series			-	289,066
Other		Various	11,806	12,568
			<u>78,268</u>	<u>380,157</u>
			<u>5,161,805</u>	<u>4,808,169</u>
Less:				
Current portion			(176,019)	(193,198)
Unamortized debt issue costs			(35,447)	(26,598)

BASIN ELECTRIC POWER COOPERATIVE AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS, Continued

Due Date	Weighted Average Interest Rate at December 31, 2025	2025	2024
Discount payable		(1,075)	-
Long-term debt, net of current portion		<u>\$ 4,949,264</u>	<u>\$ 4,588,373</u>

The estimated fair value of debt at December 31, 2025 and 2024 was \$5.1 billion and \$4.5 billion, respectively, based on cash flows discounted at interest rates for similar issues or at the current rates offered to Basin Electric for debt of comparable maturities.

The scheduled maturities of long-term debt for the next five years as of December 31, 2025 are as follows:

	2026	2027	2028	2029	2030
	(In thousands)				
Long-term debt	<u>\$ 176,019</u>	<u>\$ 184,837</u>	<u>\$ 152,297</u>	<u>\$ 209,347</u>	<u>\$ 208,265</u>

All of Basin Electric's long-term debt is secured under the Amended and Restated Indenture dated May 5, 2015 (the "Indenture"), between Basin Electric and U.S. Bank National Association, as trustee. Pursuant to the Indenture, Basin Electric created a first lien on substantially all of its tangible and certain of its intangible assets in favor of the Indenture trustee to secure certain long-term debt on a pro-rata basis.

Basin Electric's and its subsidiaries' debt agreements contain various restrictive financial and non-financial covenants which, among other matters, require Basin Electric to maintain a defined margins for interest ratio. As of December 31, 2025 Basin Electric is in compliance with all financial covenants related to the debt agreements.

All of Dakota Gas's long-term debt was secured under an Indenture dated as of May 1, 2015 between Dakota Gas and U.S. Bank, N.A., as trustee. Dakota Gas's long-term debt was also supported by an unsecured Guarantee dated as of May 8, 2015 by Basin Electric, its parent, in favor of U.S. Bank National Association, as Trustee. In December 2025, DGC's long-term debt of \$261.5 million was paid in full by means of a capital contribution by Basin Electric.

Dakota Coal's equipment notes are collateralized by security interests in certain mining equipment granted to the lender. Certain of Dakota Coal's equipment notes are also supported by an unsecured Guarantee dated as of March 23, 2012, by Basin Electric.

In order to invest in DCS and effectuate the contribution of the assets to DCS, Dakota Gas was required to receive consent and waiver of certain conditions in its Indenture from the noteholders of the senior secured notes. As a part of the consent and waiver from the noteholders, Dakota Gas made a prepayment on the notes in the amount of \$34.1 million in March 2024.

BASIN ELECTRIC POWER COOPERATIVE AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS, Continued

NOTES PAYABLE—Basin Electric has outstanding revolving credit facilities and a term loan which are included in notes payable on the consolidated balance sheets as follows:

Facility	Expiration Date	Total Availability	Outstanding Amounts as of December 31, 2025
(In thousands)			
Commercial Paper/Revolving Credit Agreement (a) (b)	March 2026	\$ 130,000	\$ 100,000
Revolving Credit Agreement	May 2030	1,250,000	-
2025 Term Loan	October 2026	375,000	375,000
Total notes payable		\$ 1,755,000	\$ 475,000

(a) The taxable and tax-exempt commercial paper programs are supported by revolving credit agreements with various banks. Balances reflect commercial paper amounts outstanding. There were no amounts outstanding under the revolving credit agreements.

(b) On March 13, 2026, Basin Electric amended and restated this credit agreement to decrease the available borrowing capacity to \$100.0 million and extend the expiration date to March 2031.

As of December 31, 2025 and 2024, the effective interest rate of the outstanding advances was 4.74 percent and 4.73 percent, respectively.

MEMBER INVESTMENT PROGRAM—Basin Electric holds notes related to funds invested by the members under a member investment program. These funds are used by Basin Electric to reduce short-term borrowings. The members receive investment earnings based on market rates, adjusted for administrative costs. The notes held as part of this program were as follows at December 31:

	2025	2024
(In thousands)		
Long-term debt, net of current portion	\$ -	\$ 4,400
Notes payable-Members	159,495	142,390
	\$ 159,495	\$ 146,790

BASIN ELECTRIC POWER COOPERATIVE AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS, Continued

12. REVENUE

The following tables disaggregate revenue by major source. The tables also includes a reconciliation of the disaggregated revenue by reportable segments. For more information on Basin Electric's business segments, see Note 17.

	Year ended December 31, 2025				
	Electric Utility	Gasification	Coal and Limestone Operations	Elimination of Intersegment	Total
	(In thousands)				
Sales of electricity to members	\$ 2,162,056	\$ -	\$ -	\$ -	\$ 2,162,056
Sales of electricity to non-members	196,428	-	-	-	196,428
Synthetic natural gas	-	105,988	-	-	105,988
Fertilizer and DEF products	-	318,982	-	-	318,982
Other byproducts	-	64,576	-	-	64,576
Lignite coal	-	-	276,028	(106,917)	169,111
Miscellaneous	7,346	2,969	28,231	-	38,546
Revenue from contracts with customers	2,365,830	492,515	304,259	(106,917)	3,055,687
Regulatory deferred revenue recognized	18,000	-	-	-	18,000
Other revenue	12,534	1,550	-	-	14,084
Total operating revenue	<u>\$ 2,396,364</u>	<u>\$ 494,065</u>	<u>\$ 304,259</u>	<u>\$ (106,917)</u>	<u>\$ 3,087,771</u>

	Year ended December 31, 2024				
	Electric Utility	Gasification	Coal and Limestone Operations	Elimination of Intersegment	Consolidated
	(In thousands)				
Sales of electricity to members	\$ 1,995,959	\$ -	\$ -	\$ -	\$ 1,995,959
Sales of electricity to non-members	205,762	-	-	-	205,762
Synthetic natural gas	-	75,926	-	-	75,926
Fertilizer and DEF products	-	227,749	-	-	227,749
Other byproducts	-	75,566	-	-	75,566
Lignite coal	-	-	234,253	(96,740)	137,513
Miscellaneous	6,500	1,395	24,651	-	32,546
Revenue from contracts with customers	2,208,221	380,636	258,904	(96,740)	2,751,021
Regulatory deferred revenue recognized	60,000	-	-	-	60,000
Other revenue	2,611	1,767	-	-	4,378
Total operating revenue	<u>\$ 2,270,832</u>	<u>\$ 382,403</u>	<u>\$ 258,904</u>	<u>\$ (96,740)</u>	<u>\$ 2,815,399</u>

BASIN ELECTRIC POWER COOPERATIVE AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS, Continued

	Year ended December 31, 2023				
	Electric Utility	Gasification	Coal and Limestone Operations	Elimination of Intersegment	Total
	(In thousands)				
Sales of electricity to members	\$ 1,926,214	\$ -	\$ -	\$ -	\$ 1,926,214
Sales of electricity to non- members	257,953	-	-	-	257,953
Synthetic natural gas	-	107,295	-	-	107,295
Fertilizer and DEF products	-	235,260	-	-	235,260
Other byproducts	-	72,131	-	-	72,131
Lignite coal	-	-	218,544	(79,779)	138,765
Miscellaneous	7,563	1,445	24,586	-	33,594
Revenue from contracts with customers	2,191,730	416,131	243,130	(79,779)	2,771,212
Regulatory deferred revenue recognized	65,000	-	-	-	65,000
Other revenue	22,808	28,098	-	-	50,906
Total operating revenue	<u>\$ 2,279,538</u>	<u>\$ 444,229</u>	<u>\$ 243,130</u>	<u>\$ (79,779)</u>	<u>\$ 2,887,118</u>

NET DEFERRED REVENUE AND OTHER REVENUE—Revenue from nonmember wholesale electricity sales of \$18.0 million, \$60.0 million and \$65.0 million that was previously deferred was recognized in 2025, 2024 and 2023, respectively, by Basin Electric’s Board of Directors, in its capacity as regulator. This deferred revenue is accounted for under ASC 980. Other revenue includes derivative revenue from hedging activities for synthetic natural gas, tar oil, and electricity sales which is accounted for under ASC 815.

CONTRACT BALANCES—At times, Basin Electric and its subsidiaries will receive payment in advance of performing an obligation under a contract. Unearned revenue, a contract liability, is recognized when this occurs. At December 31, 2025 and 2024, the unearned revenue balance (included in other current liabilities on the consolidated balance sheets) was \$7.6 million and \$301,000, respectively. There were no contract assets at December 31, 2025 and 2024. The balance in receivables, net on the consolidated balance sheets represent the unconditional right to consideration from customers.

13. INCOME TAXES

Basin Electric is a nonexempt cooperative subject to federal and state income taxation, but as a cooperative is allowed to exclude from income margins allocated as patronage capital. Basin Electric and its subsidiaries (the Consolidated Group) file a consolidated income tax return and have entered into tax-sharing agreements. Income taxes are allocated among members of the Consolidated Group based on a systematic, rational and consistent method under which such taxes approximate the amount that would have been computed on a separate company basis, subject to limitations on the Consolidated Group.

BASIN ELECTRIC POWER COOPERATIVE AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS, Continued

Basin Electric's margin before income taxes by geographic location was as follows for the years ended December 31:

	2025	2024	2023
	(In thousands)		
Margin before income taxes:			
Domestic	\$ 145,200	\$ 130,893	\$ 162,098
Foreign - Canada	602	64	294
Total margin before income taxes	<u>\$ 145,802</u>	<u>\$ 130,957</u>	<u>\$ 162,392</u>

The components of Basin Electric's income tax expense (benefit) were as follows for the years ended December 31:

	2025	2024	2023
	(In thousands)		
Current income tax expense:			
Federal	\$ 6,429	\$ 3,101	\$ 5,849
State	89	239	64
Foreign - Canada	364	(29)	124
Total current income tax expense	<u>6,882</u>	<u>3,311</u>	<u>6,037</u>
Deferred income tax benefit:			
Federal	644	(16,064)	(11,748)
State	(688)	(450)	(453)
Foreign - Canada	(308)	166	(43)
Total deferred income tax benefit	<u>(352)</u>	<u>(16,348)</u>	<u>(12,244)</u>
Total income tax expense (benefit)	<u>\$ 6,530</u>	<u>\$ (13,037)</u>	<u>\$ (6,207)</u>

BASIN ELECTRIC POWER COOPERATIVE AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS, Continued

The tax sharing agreement between Basin Electric and Dakota Gas requires reimbursement for the usage of net operating losses and other tax attributes. At December 31, 2025, Basin Electric had a receivable from Dakota Gas in the amount of \$2.5 million for a reduction of the utilization of net operating losses which is included in current tax expense. The tax effect of significant temporary differences representing deferred tax assets and liabilities were as follows at December 31:

	<u>2025</u>	<u>2024</u>
	(In thousands)	
Deferred tax assets:		
Prepayment and installment payments	\$ 53,093	\$ 58,188
Patronage loss	22,273	24,439
Lease obligation	27,024	25,998
Deferred revenue	57,120	60,900
Deferred credits	18,978	17,374
Tax credits available	16,097	15,391
Interest expense carryover	40,380	35,883
Mine related	20,915	15,378
Net operating loss carryforward	80,154	71,946
Other deferred tax assets	19,755	19,623
Valuation allowance	(35,741)	(25,766)
Total deferred tax assets	<u>320,048</u>	<u>319,354</u>
Deferred tax liabilities:		
Depreciation and property	(315,363)	(299,590)
Tax benefit transfer leases	(25,823)	(23,434)
Right-of-use lease asset	(27,016)	(25,989)
Patronage capital	(4,200)	(5,361)
Debt refinancing expense	(13,245)	(14,318)
Direct financing leases	(9,710)	(12,835)
Miscellaneous deferred expenses	(823)	-
Other deferred tax liabilities	-	(9,327)
Unrealized gains	(14,790)	(10,508)
Total deferred tax liability	<u>(410,970)</u>	<u>(401,362)</u>
Net deferred tax liability	<u>\$ (90,922)</u>	<u>\$ (82,008)</u>

The net deferred tax liability is recorded in deferred income tax liability on the consolidated balance sheets. Deferred taxes have been provided for temporary income tax differences associated with utility operations with an offsetting amount recorded as a regulatory asset as such amounts are expected to be recovered through rates charged to members at such time as the Board of Directors, in its capacity as regulator, deems appropriate.

BASIN ELECTRIC POWER COOPERATIVE AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS, Continued

Income taxes differ from the income tax expense (benefit) computed using the statutory rate for the years ended December 31 as follows:

	2025		2024		2023	
	(Dollars in thousands)					
U.S Federal statutory income tax.....	\$ 30,618	21.0 %	\$ 27,501	21.0 %	\$ 34,102	21.0 %
State income taxes, net of federal income tax benefit (a).....	(599)	(0.4)%	(211)	(0.2)%	(390)	(0.2)%
Patronage capital allocated	(22,249)	(15.3)%	(24,457)	(18.7)%	(31,770)	(19.6)%
Tax credits.....	(1,149)	(0.8)%	(1,178)	(0.9)%	-	-
Nontaxable or nondeductible items.....	(351)	(0.2)%	(266)	(0.2)%	(881)	(0.5)%
Change in regulatory asset associated with deferred taxes.....	(5,366)	(3.7)%	(20,974)	(16.0)%	(11,958)	(7.4)%
Changes in valuation allowances.....	7,034	4.8 %	7,517	5.7 %	1,619	1.0 %
Foreign tax effects - Canada.....	(121)	(0.1)%	-	-	(13)	-
Changes in unrecognized tax benefits.....	(274)	(0.2)%	(446)	(0.3)%	(246)	(0.2)%
Other:						
Noncontrolling interest.....	(1,633)	(1.1)%	(2,030)	(1.6)%	(1,538)	(0.9)%
Other.....	620	0.5 %	1,507	1.2 %	4,868	3.0 %
Income tax expense (benefit) and effective income tax rate.....	\$ 6,530	4.5 %	\$ (13,037)	(10.0)%	\$ (6,207)	(3.8)%

(a) State taxes in North Dakota made up the majority (greater than 50 percent) of the tax effect in this category.

Basin Electric had available federal and state research and carbon sequestration tax credit carryforwards of approximately \$16.1 million. The research tax credits expire in varying amounts from 2026 through 2039 and the carbon sequestration credits generated in 2025 expire in 2045. Basin Electric has a consolidated net operating loss carryforward as of December 31, 2025 of \$381.7 million, and a patron net operating loss of \$106.1 million. The losses are carried forward indefinitely.

Deferred tax assets are reduced by a valuation allowance when it is more likely than not that a portion or all of the deferred tax assets will not be realized. The valuation allowance on deferred tax assets increased from \$25.8 million in 2024 to \$35.7 million in 2025. It is more likely than not that the benefit from certain federal and state net operating losses and federal and state tax credits will not be fully realized. In recognition of this risk, Basin Electric recorded an incremental partial valuation allowance on the related deferred tax assets. Basin Electric has a federal interest expense carryforward that is carried forward indefinitely. As it is unlikely the benefit from the interest expense carryforward will be fully realized, Basin Electric recorded an incremental partial valuation allowance on the related deferred tax asset.

BASIN ELECTRIC POWER COOPERATIVE AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS, Continued

In accordance with the provisions of ASC 740, *Income Taxes*, Basin Electric records a liability for unrecognized tax benefits. A reconciliation of the beginning and ending amount of the liability for unrecognized tax benefits is as follows:

	2025	2024	2023
	(In thousands)		
Balance, January 1	\$ 5,946	\$ 6,392	\$ 6,638
Addition for tax positions of current period	199	5	-
Reduction for tax positions of prior periods	(473)	(451)	(246)
Balance, December 31	<u>\$ 5,672</u>	<u>\$ 5,946</u>	<u>\$ 6,392</u>

Basin Electric recognizes interest and penalties related to unrecognized tax benefits, if any, in the respective interest and penalties expense accounts and not in the income tax expense (benefit) on the consolidated statements of operations.

As of December 31, 2025, with limited exceptions, Basin Electric is no longer subject to examinations by taxing authorities for tax years prior to 2022 for federal and prior to 2021 for most states and for Canadian taxing authorities. Management does not believe future settlements with the IRS will be material to Basin Electric's financial position.

Income taxes paid (net of refunds) for the years ended December 31 as follows:

	2025	2024	2023
	(In thousands)		
Cash paid (received) for income taxes, net:			
Federal	\$ 50	\$ 2,000	\$ (743)
State	(22)	228	88
Foreign - Canada	125	183	52
Total income taxes paid (net of refunds)	<u>\$ 153</u>	<u>\$ 2,411</u>	<u>\$ (603)</u>
State income taxes paid (net of refunds) exceeding 5 percent of total income taxes paid (net of refunds):			
Texas	\$ 88	\$ 32	\$ 87
Minnesota	\$ (111)	\$ 193	(a)

(a) Jurisdiction below the threshold for the period presented.

14. ASSETS AND LIABILITIES MEASURED AT FAIR VALUE

Level 1 inputs utilize observable market data in active markets for identical assets or liabilities. Level 2 inputs consist of observable market data, other than that included in Level 1, that is either directly or indirectly observable. Level 3 inputs consist of unobservable market data which are typically based on an entity's own assumptions of what a market participant would use in pricing an asset or liability as there is little, if any, related market activity. In instances where the determination of the fair value measurement is based on inputs from different levels of the fair value hierarchy, the level in the fair value hierarchy within which the entire fair value measurement falls is based on the lowest level input that is significant to the fair value measurement in its entirety. Basin Electric's assessment of the significance of a particular input to the fair value measurement in its entirety requires judgment, and considers factors specific to the asset or liability.

BASIN ELECTRIC POWER COOPERATIVE AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS, Continued

On December 31, 2025 and 2024, Basin Electric had government obligations, equity securities, bond market funds and corporate bonds included in restricted and designated investments, mine related assets and other investments, recorded at a fair value, using quoted prices in active markets for identical assets as the fair value measurement (Level 1).

Basin Electric recorded derivative financial instruments including commodity contracts and interest rate swaps using significant other observable inputs as the fair value measurement (Level 2). The fair value for commodity contracts is determined by comparing the difference between the net present value of the cash flows for the commodity contracts at their initial price and the current market price. The initial price is quoted in the commodity contract and the current market price is corroborated by observable market data. The fair value for interest rate swap contracts is determined by comparing the difference between the net present value of the cash flows for the swaps at their initial fixed rate and the current market interest rate. The initial fixed rate is quoted in the swap agreement and the current market interest rate is corroborated by observable market data.

The following table summarizes assets and liabilities measured at fair value on a recurring basis as of December 31, 2025, aggregated by the level in the fair value hierarchy within which those measurements fall:

	Fair Value	Fair Value Measurements Using		
		Quoted Prices in Active Markets for Identical Assets and Liabilities (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
(In thousands)				
Assets:				
Investments:				
Equities and equity funds	\$ 128,659	\$ 128,659	\$ -	\$ -
Corporate and government bonds	1,971	1,971	-	-
Bond market funds	73,004	73,004	-	-
	203,634	203,634	-	-
Commodity derivatives	42,880	-	42,880	-
	<u>\$ 246,514</u>	<u>\$ 203,634</u>	<u>\$ 42,880</u>	<u>\$ -</u>
Liabilities:				
Interest rate swaps	\$ 22,031	\$ -	\$ 22,031	\$ -
Commodity derivatives	31,440	-	31,440	-
	<u>\$ 53,471</u>	<u>\$ -</u>	<u>\$ 53,471</u>	<u>\$ -</u>

BASIN ELECTRIC POWER COOPERATIVE AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS, Continued

The following table summarizes assets and liabilities measured at fair value on a recurring basis as of December 31, 2024, aggregated by the level in the fair value hierarchy within which those measurements fall:

	Fair Value Measurements Using			
	Fair Value	Quoted Prices in Active Markets for Identical Assets and Liabilities (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
(In thousands)				
Assets:				
Investments:				
Equities and equity funds	\$ 120,596	\$ 120,596	\$ -	\$ -
Corporate and government bonds	117,093	117,093	-	-
Bond market funds	57,582	57,582	-	-
	295,271	295,271	-	-
Commodity derivatives	34,560	-	34,560	-
	<u>\$ 329,831</u>	<u>\$ 295,271</u>	<u>\$ 34,560</u>	<u>\$ -</u>
Liabilities:				
Interest rate swaps	\$ 18,351	\$ -	\$ 18,351	\$ -
Commodity derivatives	18,903	-	18,903	-
	<u>\$ 37,254</u>	<u>\$ -</u>	<u>\$ 37,254</u>	<u>\$ -</u>

15. EMPLOYEE BENEFIT PLANS

POSTRETIREMENT BENEFITS—Employees of Basin Electric, Dakota Gas, and MLC retiring at or after attaining age 55 and completing five years of service may elect to continue medical and dental benefits by paying premiums to Basin Electric, Dakota Gas or MLC for participating in the current employee plan, subject to deductible, coinsurance and copayment provisions. Eligible dependents of retired employees continue to receive benefits after the death of the former employee, with certain limitations. Participation in Basin Electric’s, Dakota Gas’s or MLC’s medical plan can continue until the retiree or spouse becomes eligible for Medicare. Once a retiree becomes eligible for Medicare, the spouse may continue under each of the plans until the spouse becomes eligible for Medicare. Basin Electric, Dakota Gas, and MLC reserve the right to change or terminate these benefits at any time.

Basin Electric, Dakota Gas and MLC fund postretirement medical benefits from general funds, and in 2025, 2024 and 2023 funding was \$1.2 million, \$2.2 million and \$2.4 million, respectively.

Coteau also maintains medical care and life insurance plans which provide benefits to eligible retired employees.

BASIN ELECTRIC POWER COOPERATIVE AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS, Continued

The following sets forth the changes in the postretirement benefit obligation and plan assets during the year and amounts recognized in the consolidated balance sheets, as of December 31:

	Basin Electric and Subsidiaries		Coteau	
	2025	2024	2025	2024
	(In thousands)			
Change in postretirement benefit obligation:				
Balance at January 1	\$ 21,947	\$ 24,061	\$ 1,320	\$ 2,021
Service cost	1,278	1,168	19	22
Interest cost	1,031	934	65	92
Actuarial (gain) loss	(3,206)	(1,021)	251	(710)
Assumption changes	(6,229)	(970)	-	-
Benefit payments	(4,766)	(6,924)	(514)	(105)
Plan participant contributions	3,571	4,699	-	-
Balance at December 31	\$ 13,626	\$ 21,947	\$ 1,141	\$ 1,320
Change in plan assets:				
Fair value of plan assets at beginning of year	\$ -	\$ -	\$ -	\$ -
Employer contributions	1,195	2,225	514	105
Plan participant contributions	3,571	4,699	-	-
Benefit payments	(4,766)	(6,924)	(514)	(105)
Fair value of plan assets at end of year	\$ -	\$ -	\$ -	\$ -
As of December 31, the funded status of the plan was:				
Postretirement benefit liability	\$ 13,626	\$ 21,947	\$ 1,141	\$ 1,320
Amounts recognized in the balance sheets are:				
Other current liabilities	\$ 1,420	\$ 1,991	\$ 152	\$ 218
Other noncurrent liabilities	12,206	19,956	989	1,102
Net amount recognized	\$ 13,626	\$ 21,947	\$ 1,141	\$ 1,320
Amounts not yet reflected in periodic postretirement benefit expense and included in accumulated other comprehensive income (loss) and regulatory liabilities:				
Prior service cost	\$ (308)	\$ (538)	\$ -	\$ -
Actuarial gain	31,695	23,909	2,176	3,103
Accumulated other comprehensive income and regulatory liabilities	\$ 31,387	\$ 23,371	\$ 2,176	\$ 3,103

BASIN ELECTRIC POWER COOPERATIVE AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS, Continued

Net periodic postretirement benefit expense (income) for the years ended December 31, 2025, 2024, and 2023 for Basin Electric and subsidiaries was \$891,000, \$497,000 and \$1.0 million, respectively, and for Coteau was \$(592,000), \$(548,000) and \$(822,000), respectively.

	Basin Electric and Subsidiaries			Coteau		
	2025	2024	2023	2025	2024	2023
	(In thousands)					
Other changes recognized in other comprehensive income (loss) and regulatory liabilities:						
Net (gain) loss arising during the period	\$ (9,435)	\$ (1,990)	\$ 3,008	\$ 251	\$ (710)	\$ (156)
Amortization of prior service (cost) credit	(230)	(233)	(232)	-	-	139
Amortization of actuarial gain	1,649	1,838	1,608	676	662	822
Total recognized in other comprehensive income (loss) and regulatory liabilities	\$ (8,016)	\$ (385)	\$ 4,384	\$ 927	\$ (48)	\$ 805

Assumptions used in accounting for the postretirement benefit obligations were as follows for the years ended December 31:

	Basin Electric and Subsidiaries		Coteau	
	2025	2024	2025	2024
Weighted-average discount rates	5.41%	5.62 %	4.63%	5.26 %
Initial health care cost trend rate	8.50%	6.74 %	7.50%	6.50 %
Ultimate health care cost trend rate	4.00%	4.00 %	4.75%	4.75 %
Year that the rate reaches the ultimate trend rate	2051	2048	2037	2033

Assumptions used to determine net periodic postretirement benefit expense (income) were as follows for the years ended December 31:

	Basin Electric and Subsidiaries		Coteau	
	2025	2024	2025	2024
Weighted-average discount rates	5.62%	5.14%	5.26%	4.98%
Initial health care cost trend rate	6.74%	7.37%	6.50%	6.50%
Ultimate health care cost trend rate	4.00%	4.00%	4.75%	4.75%
Year that the rate reaches the ultimate trend rate	2048	2048	2033	2033

Basin Electric and its subsidiaries and Coteau expect to make contributions of \$1.4 million and \$153,000, respectively, in 2026 to their postretirement benefit plans.

BASIN ELECTRIC POWER COOPERATIVE AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS, Continued

The following are the expected future benefits to be paid:

	Basin Electric and Subsidiaries		Coteau	
	(In thousands)			
2026	\$	1,420	\$	153
2027	\$	1,326	\$	157
2028	\$	1,147	\$	151
2029	\$	1,045	\$	120
2030	\$	957	\$	131
2031-2035	\$	4,627	\$	529

DEFINED BENEFIT PLANS

NRECA RS PLAN—Pension benefits for Basin Electric and Dakota Gas employees participating in the pension plan are provided through participation in the National Rural Electric Cooperative Association (NRECA) Retirement Security Plan (RS Plan) which is a defined benefit pension plan qualified under Section 401 and tax-exempt under Section 501(a) of the Internal Revenue code. It is a multiemployer plan under GAAP.

A unique characteristic of a multiemployer plan compared to a single employer plan is that all plan assets are available to pay benefits of any plan participant. Separate asset accounts are not maintained for participating employers. This means that assets contributed by one employer may be used to provide benefits to employees of other participating employers.

Basin Electric and Dakota Gas contributions to the RS Plan in 2025 and in 2024 represented less than 5 percent of the total contributions made to the RS Plan by all participating employers. Pension costs charged to expense during 2025, 2024 and 2023 were \$37.5 million, \$36.8 million and \$36.0 million, respectively.

In the RS Plan, a “zone status” determination is not required, and therefore not determined, under the Pension Protection Act of 2006. In addition, the accumulated benefit obligations and plan assets are not determined or allocated separately by individual employer. In total, the RS Plan was over 80 percent funded at January 1, 2025 and 2024.

Future contribution requirements are determined each year as part of the actuarial valuation of the plan and may change as a result of plan experience.

BCS AND COTEAU PLANS—BCS’s former United Mine Workers of America employees are covered under a defined benefit plan which is funded by BCS.

Substantially all of Coteau’s salaried employees hired prior to January 1, 2000, participate in the Coteau Pension Plan (the Plan), a noncontributory defined benefit plan sponsored by NACoal. Benefits under the defined benefit pension plan are based on years of service and average compensation during certain periods. The Plan benefits were frozen effective December 31, 2013. Employees whose benefits were frozen subsequently receive retirement benefits under defined contribution plans. In 2025, Coteau terminated the Plan and settled all future obligations by transferring the remaining benefit obligations to a third-party insurance company. The excess funds from the Plan will be utilized by the Coteau defined contribution plan, which is a qualified replacement plan. These funds will be used for future profit sharing contributions to eligible defined contribution plan participants. A non-cash pension settlement charge of

BASIN ELECTRIC POWER COOPERATIVE AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS, Continued

\$2.8 million was recognized. The settlement charge accelerated the loss recorded in accumulated other comprehensive income that would have otherwise been recognized in subsequent periods.

The following sets forth the changes in the pension benefit obligation and plan assets during the year and amounts recognized in the consolidated balance sheets as of December 31:

	BCS		Coteau	
	2025	2024	2025	2024
(In thousands)				
Change in pension benefit obligation:				
Balance at January 1	\$ 2,576	\$ 2,800	\$ 67,945	\$ 72,754
Interest cost	128	124	3,016	3,545
Actuarial (gain) loss	(19)	(70)	3,588	(2,332)
Benefits payments	(259)	(278)	(6,026)	(6,022)
Settlements	-	-	(68,523)	-
Balance at December 31	<u>\$ 2,426</u>	<u>\$ 2,576</u>	<u>\$ -</u>	<u>\$ 67,945</u>
Change in plan assets:				
Fair value of plan assets at beginning of year	\$ 2,848	\$ 2,906	\$ 94,672	\$ 93,365
Actual return on plan assets	275	220	6,465	7,329
Employer contributions	-	-	-	-
Benefits payments	(259)	(278)	(6,026)	(6,022)
Settlements	-	-	(68,523)	-
Fair value of plan assets at end of year	<u>\$ 2,864</u>	<u>\$ 2,848</u>	<u>\$ 26,588</u>	<u>\$ 94,672</u>
As of December 31, the funded status of the plan was:				
Fair value of plan assets	\$ 2,864	\$ 2,848	\$ 26,588	\$ 94,672
Accumulated postretirement benefit liability	2,426	2,576	-	67,945
Funded status – over	<u>\$ 438</u>	<u>\$ 272</u>	<u>\$ 26,588</u>	<u>\$ 26,727</u>
Amounts recognized in the balance sheets are:				
Other investments and special funds	\$ 438	\$ 272	\$ 26,588	\$ 26,727
Amounts not yet reflected in periodic postretirement benefit expense and included in accumulated other comprehensive income (loss):				
Actuarial loss	\$ (630)	\$ (837)	\$ -	\$ (2,285)
Accumulated other comprehensive income (loss)	<u>\$ (630)</u>	<u>\$ (837)</u>	<u>\$ -</u>	<u>\$ (2,285)</u>

BASIN ELECTRIC POWER COOPERATIVE AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS, Continued

Net periodic pension expense (income) for the years ended December 31, 2025, 2024 and 2023 for BCS was \$41,000, \$49,000 and \$83,000, respectively and for Coteau was \$2.4 million, \$(3.2) million and \$(3.0) million, respectively.

	BCS			Coteau		
	2025	2024	2023	2025	2024	2023
	(In thousands)					
Other changes recognized in other comprehensive income (loss):						
Net (gain) loss arising during the period	\$ (159)	\$ (152)	\$ (184)	\$ 546	\$ (2,944)	\$ (4,769)
Amortization of actuarial loss	(48)	(63)	(83)	-	-	-
Recognition of settlement cost	-	-	-	(2,831)	-	-
Total recognized in other comprehensive income (loss)	<u>\$ (207)</u>	<u>\$ (215)</u>	<u>\$ (267)</u>	<u>\$ (2,285)</u>	<u>\$ (2,944)</u>	<u>\$ (4,769)</u>

Assumptions used to account for the pension benefit obligation were as follows for the years ended December 31:

	BCS		Coteau	
	2025	2024	2025	2024
Weighted-average discount rate	4.94%	5.27%	N/A	5.56%

The assumptions used to determine net periodic pension expense were as follows for the years ended December 31:

	BCS		Coteau	
	2025	2024	2025	2024
Weighted-average discount rate	5.27%	4.65%	5.56%	5.07%
Expected return on plan assets	5.00%	5.00%	4.40%	7.00%

BCS does not expect to make any contributions in 2026 to its defined benefit plans. The following are the expected future benefit payments for the BCS Plan:

	BCS
	(In thousands)
2026	\$ 255
2027	\$ 248
2028	\$ 241
2029	\$ 233
2030	\$ 224
2031-2035	\$ 974

BASIN ELECTRIC POWER COOPERATIVE AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS, Continued

The following is the actual and target allocation percentages for the Plan and BCS Plan assets as of December 31, 2025:

	BCS	
	Actual Allocation	Target Allocation
Fixed income securities	66.2%	60.0%
Equity securities	28.8%	37.0%
Other	5.0%	3.0%
	<u>100.0%</u>	

BCS Plan assets are invested with a trust that is responsible for maintaining an appropriate investment ratio in common stocks, long-term corporate bonds and money market funds.

DEFINED CONTRIBUTION PLANS—Basin Electric, Dakota Gas and MLC have qualified tax deferred savings plans for eligible employees. Eligible participants of the tax deferred savings plans may make pre-tax and after-tax contributions, as defined, with Basin Electric, Dakota Gas and MLC matching various percentages of the participants' annual compensation. Contributions to these plans by Basin Electric, Dakota Gas, and MLC were \$17.6 million, \$15.0 million and \$13.1 million for 2025, 2024 and 2023, respectively.

For employees hired after December 31, 1999, Coteau established a defined contribution plan which requires Coteau to make retirement contributions based on a formula using age and salary as components of the calculation. Employees are vested at a rate of 20 percent for each year of service and are 100 percent vested after five years of employment. Coteau recorded contribution expense of approximately \$3.6 million, \$3.5 million and \$3.3 million related to this plan in 2025, 2024 and 2023, respectively.

Substantially all of Coteau's salaried employees also participate in a defined contribution plan sponsored by NACoal. Employee contributions are matched by Coteau up to a limit of 5 percent of the employee's salary. Coteau's contributions to this plan were approximately \$3.4 million, \$3.2 million and \$2.7 million in 2025, 2024 and 2023, respectively.

Under the provisions of the lignite sales agreement between Dakota Coal and Coteau, retirement related costs are recovered as a cost of coal as tonnage is sold.

16. ASSET RETIREMENT OBLIGATIONS

An asset retirement obligation is the result of legal or contractual obligations associated with the retirement of a tangible long-lived asset that results from the acquisition, construction, or development and/or the normal operation of a long-lived asset. Basin Electric and Coteau determine these obligations based on an estimated asset retirement cost adjusted for inflation and projected to the estimated settlement dates, and discounted using a credit-adjusted risk-free interest rate.

BASIN ELECTRIC POWER COOPERATIVE AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS, Continued

A reconciliation of the beginning and ending aggregate carrying amount of the asset retirement obligation included in other noncurrent liabilities on the consolidated balance sheets is as follows:

	2025	2024
	(In thousands)	
Balance, January 1	\$ 216,721	\$ 214,666
Additions and revisions	27,785	(2,375)
Accretion expense	14,791	12,851
Liabilities settled	(2,117)	(8,421)
Balance, December 31	<u>\$ 257,180</u>	<u>\$ 216,721</u>

17. SEGMENT REPORTING

Basin Electric's reportable segments include the Electric Utility, Gasification, and Coal and Limestone Operations. Certain activities that support the reportable segments, ancillary projects, or operating segments that do not meet the quantitative threshold for a reportable segment are presented as Other. The operating segments are based on Basin Electric's method of internal reporting that the Chief Operating Decision Maker (CODM) reviews to make decisions on overall resource allocation and to assess performance. The CODM is Basin Electric's Chief Executive Officer and General Manager. The CODM reviews actual financial information and forecasted financial information at an operating segment level and primarily uses segment net margin and earnings for making decisions on resource allocation and assessing performance. The CODM uses segment net income in assessing financial performance on a monthly basis, reviewing and approving annual operating budgets and long-term forecasts, allocating capital or financial resources to our segments and in making strategic decisions.

The Electric Utility reportable segment provides wholesale electric service and other ancillary services to Basin Electric's members throughout its service territory with its own electrical generation and transmission assets and various contractual arrangements.

The Gasification reportable segment includes Dakota Gasification Company (DGC). DGC operates a gasification facility that converts lignite coal into synthetic natural gas and other products including fertilizers, diesel exhaust fluid, carbon dioxide, and other oil and chemical products.

The Coal and Limestone Operations reportable segment purchases coal and coordinates deliveries of coal to Basin Electric's Electric Utility generation facilities and Gasification operations. It also produces lime and limestone that is used for emissions control at the generation facilities.

Other consists of Basin Cooperative Services, Nemadji River Generation, and certain tax adjustments and other activity not associated with the reportable segments. Basin Cooperative Services provides certain nonutility property management services to Basin Electric. Nemadji River Generation owned an undivided interest in a proposed electric generation facility. In January 2026, Nemadji River Generation exited the project.

Substantially all of Basin Electric's assets and revenues are located in the United States. Revenues and assets outside the United States were not material for the periods presented.

Major Customer – For the years ended December 31, 2025, 2024, and 2023, revenues from a single customer, Upper Missouri, represented approximately 29.9 percent, 30.5 percent, and 27.5 percent respectively, of Basin Electric's consolidated revenues, all of which were attributable to the Electric Utility reportable segment. No other customer contributed 10 percent or more of consolidated revenues for the periods.

BASIN ELECTRIC POWER COOPERATIVE AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS, Continued

Information on Basin Electric's segments as of December 31 and for the years ended December 31 was as follows:

	2025			Total Reportable Segments
	Electric Utility	Gasification	Coal and Limestone Operations	
(In thousands)				
Operating revenue:				
External	\$ 2,396,364	\$ 494,065	\$ 197,342	\$ 3,087,771
Intersegment	-	-	106,917	106,917
	<u>2,396,364</u>	<u>494,065</u>	<u>304,259</u>	<u>3,194,688</u>
Elimination of intersegment revenue				(106,917)
Total operating revenue				<u>\$ 3,087,771</u>
Less:				
Electric fuel and purchased power	1,116,603	-	-	
Electric operations and maintenance	758,006	-	-	
Cost of products sold:				
External	-	361,780	235,452	
Intersegment	-	106,917	-	
Nonelectric selling, general and administrative	-	104,800	9,810	
Depreciation, depletion and amortization	216,612	41,537	18,612	
Impairment of assets	-	4,164	-	
Interest and other charges, net:				
External	229,173	34,671	13,669	
Intersegment	35,027	-	-	
Other income	(64,981)	(122,072)	(16,217)	
Income tax expense (benefit)	1,212	(2,981)	7,235	
Net margin and earnings attributable to noncontrolling interest	-	-	23,000	
Segment net margin and earnings	<u>104,712</u>	<u>(34,751)</u>	<u>12,698</u>	<u>82,659</u>
Elimination of intercompany loss				35,027
Other net expenses				(1,414)
Net margin and earnings attributable to Basin Electric				<u>\$ 116,272</u>
Segment capital expenditures ^(a)				
	\$ 757,474	\$ 28,192	\$ 21,558	\$ 807,224
Other capital expenditures				-
Total consolidated capital expenditures				<u>\$ 807,224</u>
Segment total assets				
	\$ 9,014,439	\$ 1,053,066	\$ 568,599	\$ 10,636,104
Other assets				35,504
Elimination of intersegment assets				(1,273,951)
Total consolidated assets				<u>\$ 9,397,657</u>

(a) Does not include accruals for property, plant and equipment as disclosed in the supplemental cash flow information to the consolidated statements of cash flows.

BASIN ELECTRIC POWER COOPERATIVE AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS, Continued

	2024			Total Reportable Segments
	Electric Utility	Gasification	Coal and Limestone Operations	
	(In thousands)			
Operating revenue:				
External	\$ 2,270,832	\$ 382,403	\$ 162,164	\$ 2,815,399
Intersegment	-	-	96,740	96,740
	<u>2,270,832</u>	<u>382,403</u>	<u>258,904</u>	<u>2,912,139</u>
Elimination of intersegment revenue				(96,740)
Total operating revenue				<u>\$ 2,815,399</u>
Less:				
Electric fuel and purchased power	1,074,416	-	-	
Electric operations and maintenance	679,558	-	-	
Cost of products sold:				
External	-	325,257	217,038	
Intersegment	-	96,740	-	
Nonelectric selling, general and administrative	-	39,373	8,752	
Depreciation, depletion and amortization ...	204,903	38,532	16,042	
Impairment of assets	-	4,013	-	
Interest and other charges, net:				
External	216,511	36,967	11,379	
Intersegment	56,804	-	-	
Other income	(77,804)	(125,968)	(16,467)	
Income tax expense (benefit)	(9,139)	(1,211)	2,603	
Net margin and earnings attributable to noncontrolling interest	-	-	23,215	
Segment net margin and earnings	125,583	(31,300)	(3,658)	90,625
Elimination of intercompany loss				56,804
Impairment of assets, net of tax				(25,504)
Other net expenses				(1,146)
Net margin and earnings attributable to Basin Electric				\$ 120,779
Segment capital expenditures ^(a)	\$ 561,450	\$ 13,946	\$ 68,355	\$ 643,751
Other capital expenditures				1,375
Total consolidated capital expenditures				<u>\$ 645,126</u>
Segment total assets	\$ 7,770,419	\$ 1,051,134	\$ 528,844	\$ 9,350,397
Other assets				33,015
Elimination of intersegment assets				(888,630)
Total consolidated assets				<u>\$ 8,494,782</u>

(a) Does not include accruals for property, plant and equipment as disclosed in the supplemental cash flow information to the consolidated statements of cash flows.

BASIN ELECTRIC POWER COOPERATIVE AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS, Continued

	2023			Total Reportable Segments
	Electric Utility	Gasification	Coal and Limestone Operations	
(In thousands)				
Operating revenue:				
External	\$ 2,279,538	\$ 444,229	\$ 163,351	\$ 2,887,118
Intersegment	-	-	79,779	79,779
	<u>2,279,538</u>	<u>444,229</u>	<u>243,130</u>	<u>2,966,897</u>
Elimination of intersegment revenue				(79,779)
Total operating revenue				<u>\$ 2,887,118</u>
Less:				
Electric fuel and purchased power	1,077,496	-	-	
Electric operations and maintenance	662,056	-	-	
Cost of products sold:				
External	-	335,448	208,991	
Intersegment	-	79,779	-	
Nonelectric selling, general and administrative	-	33,525	5,722	
Depreciation, depletion and amortization	203,527	32,883	13,090	
Impairment of assets	-	5,035	-	
Interest and other charges, net:				
External	221,013	26,533	8,157	
Intersegment	47,722	-	-	
Other income	(83,548)	(9,252)	(15,608)	
Income tax expense (benefit)	1,304	(12,000)	3,109	
Net margin and earnings attributable to noncontrolling interest	-	-	21,083	
Segment net margin and earnings	149,968	(47,722)	(1,414)	100,832
Elimination of intercompany loss				47,722
Other net expenses				(1,038)
Net margin and earnings attributable to Basin Electric				\$ 147,516
Segment capital expenditures ^(a)				
Other capital expenditures	\$ 469,748	\$ 31,095	\$ 17,449	\$ 518,292
Total consolidated capital expenditures				<u>\$ 524,639</u>
Segment total assets				
Other assets	\$ 7,685,441	\$ 1,034,954	\$ 454,891	\$ 9,175,286
Elimination of intersegment assets				(884,193)
Total consolidated assets				<u>\$ 8,345,988</u>

(a) Does not include accruals for property, plant and equipment as disclosed in the supplemental cash flow information to the consolidated statements of cash flows.

BASIN ELECTRIC POWER COOPERATIVE AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS, Continued

18. COMMITMENTS AND CONTINGENCIES

POWER PURCHASE COMMITMENTS—Basin Electric entered into various power purchase contracts with terms ranging from one to 50 years. The estimated commitments under these contracts as of December 31, 2025 were \$423.9 million in 2026, \$447.4 million in 2027, \$468.3 million in 2028, \$451.9 million in 2029, \$442.0 million in 2030, and \$5.6 billion thereafter. Amounts purchased under the contracts totaled \$364.5 million in 2025, \$338.5 million in 2024, and \$317.0 million in 2023.

Basin Electric entered into various power purchase agreements with its Class A member, Corn Belt Power Cooperative (Corn Belt), under which Basin Electric buys substantially all of the output from Corn Belt's generation resources at cost through December 2075. Basin Electric also entered into a transmission lease agreement with Corn Belt which expires in December 2075. ASC 810, *Consolidation*, requires that certain of Corn Belt's generation assets and liabilities associated with the power purchase agreements be consolidated in Basin Electric's consolidated balance sheets. As of December 31, 2025 and 2024, the assets and liabilities of Corn Belt included in the consolidated balance sheets totaled \$8.6 million and \$9.8 million, respectively.

CONTRACT COMMITMENTS—Basin Electric has outstanding contractual commitments for pipeline transportation totaling \$8.8 million as of December 31, 2025. Basin Electric also has various other outstanding contractual commitments totaling \$2.9 billion as of December 31, 2025, for various construction projects, equipment purchases, supplies, and for miscellaneous services to be provided.

Coteau has outstanding commitments of \$4.1 million to purchase equipment and \$1.0 million committed under various diesel fuel contracts through October 2026.

MINE CLOSING COSTS AND COAL PURCHASE COMMITMENTS—Under the terms of the Coteau Lignite Sales Agreement (Agreement) between Dakota Coal and Coteau, Dakota Coal is obligated to purchase all of its lignite requirements for AVS, the Synfuels Plant and LOS from Coteau, and Coteau is obligated to sell and deliver the required coal to Dakota Coal from contractually defined dedicated coal reserves. The coal purchase price includes all costs incurred by Coteau for development and operation of the dedicated coal reserves and may include costs to be incurred in connection with the Freedom Mine closing. During 2025, 2024 and 2023, Dakota Coal paid \$263.2 million, \$246.5 million and \$235.0 million, respectively, to Coteau for coal purchased under the lignite sales agreement. As a result of applying ASC 810, Coteau is consolidated with Dakota Coal and coal purchases from Coteau are eliminated within the consolidated financial statements.

Under certain federal and state regulations, Coteau is required to reclaim land disturbed as a result of mining. Reclamation of disturbed land is a continuous process throughout the term of the Agreement. Costs of ongoing reclamation are charged to expense in the period incurred and are recovered as a cost of coal as tonnage is sold to Dakota Coal. Costs to complete reclamation after mining is completed in a specific mine area are reimbursed under the Agreement as costs of reclamation are actually incurred.

Coteau accounts for its asset retirement obligations under ASC 410, *Asset Retirement and Environmental Obligations*, which provides accounting requirements for retirement obligations associated with tangible long-lived assets and requires that an asset's retirement cost be capitalized as part of the cost of the related long-lived asset and subsequently allocated to expense using a systematic and rational method.

Coteau's annual costs related to amortization of the asset and accretion of the liability totaled \$9.9 million, \$6.5 million, and \$6.2 million in 2025, 2024 and 2023, respectively.

Dakota Coal has established designated funds for mine closing costs. The Agreement includes provisions whereby, upon expiration of the agreement, Dakota Coal has the option to purchase the

BASIN ELECTRIC POWER COOPERATIVE AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS, Continued

outstanding common stock of Coteau for its book value from NACoal. Dakota Coal may exercise this option only if Coteau has not exercised its right to extend the Agreement. NACoal has the option to require Dakota Coal to purchase the outstanding stock of Coteau for its book value in the event all of the plants Dakota Coal presently sells lignite coal to are closed or if lignite coal may no longer be legally mined in North Dakota and Dakota Coal exercises its right to terminate the Agreement with Coteau. Under the current mine plan, mining is anticipated to cease in 2047.

COAL PURCHASE AND FINANCING COMMITMENTS—Basin Electric, on behalf of the MBPP, has executed an agreement with Western Fuels for all coal purchase requirements through the life of LRS, with an option to extend the contract with approval by both parties. The average price of coal under this agreement during 2025, 2024 and 2023 was approximately \$23.19, \$22.75, and \$22.23 per ton, respectively.

Basin Electric executed an agreement with Western Fuels for all coal purchase requirements through the life of DFS, with an option to extend the contract with approval by both parties. Coal purchased under this agreement is used at the DFS. The average price of coal purchased under this agreement during 2025, 2024, and 2023 was approximately \$12.98, \$15.67, and \$14.91 per ton, respectively.

RECLAMATION GUARANTEES—Basin Electric provides guarantees of certain reclamation obligations of Coteau. These guarantees cover the reclamation of mined areas as required by the State of North Dakota's Public Service Commission (PSC). The bonds are released by the PSC after a period of time (generally ten years after final reclamation is completed) when it has been determined that the mined area has been returned to its original condition. As of December 31, 2025, the aggregated value of these guarantees is \$215.0 million.

Basin Electric guarantees certain reclamation obligations of WFW. Those guarantees cover the reclamation of mined areas as approved by the Wyoming Department of Environmental Quality (WDEQ) with the use of surety bonds. The bonds are released by the WDEQ after a period of time (generally ten years after final reclamation is completed) when it has been determined that the mined area has been returned to its approved post-mining use. As of December 31, 2025, the aggregated value of these guarantees is \$31.9 million.

DEBT GUARANTEE—Basin Electric guarantees, on an unsecured basis, a certain debt obligation of Dakota Coal totaling \$21.4 million as of December 31, 2025. In the event Dakota Coal defaults under this obligation, Basin Electric would be required to make payments under its guarantee.

DISMANTLEMENT COSTS—The county zoning permit requires Dakota Gas to dismantle the Synfuels Plant at such time that operations or other alternative uses approved by the Board of County Commissioners are terminated. Although Dakota Gas has no current plans to cease operations at the plant site, in accordance with ASC 410, Dakota Gas accrues an obligation for the eventual dismantlement and discontinuation of use of the Synfuels Plant.

LEASE INDEMNIFICATIONS—In general, under the terms of Basin Electric's sale and leaseback agreements discussed in Note 10, the lessors are indemnified should certain disqualifying events occur resulting in the recapture of tax credits, accelerated cost recovery deductions and interest deductions. Management believes that if indemnification occurs, there will not be a material adverse effect on Basin Electric's financial position, results of operations or cash flows.

CO₂ SALES COMMITMENTS—Dakota Gas has contracts involving commitments for the sale of CO₂ for enhanced oil recovery. These agreements extend through December 2027.

BASIN ELECTRIC POWER COOPERATIVE AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS, Continued

LEGAL

CARBON CAPTURE AND SEQUESTRATION—In February 2024, Dakota Gas entered into an LLC agreement with an investor in which DCS has been formed to monetize tax credits for the CO₂ it sequesters. Dakota Gas has made certain representations to the investor with respect to the project qualifying for the credits as well as to the level of the credit. Dakota Gas will be liable to indemnify the investor to the extent the tax credits are disqualified or recaptured by the IRS. In February 2024, Dakota Gas procured tax credit insurance for protection of liability under certain conditions. Basin Electric has provided a limited guarantee of Dakota Gas’s obligations under the project agreements.

CCR RULE—The 2015 Coal Combustion Residuals Rule (CCR Rule) mandated closure of unlined surface impoundments upon a specified triggering event. If after multiple levels of monitoring and an alternate source demonstration, a statistically significant level of contamination could not be attributed to another source, a company was required to retrofit or close a surface impoundment.

In August 2018, the D.C. Circuit Court of Appeals vacated and remanded to EPA three provisions of the original 2015 CCR Rule including the provision allowing unlined surface impoundments to continue to operate unless they detected a leak. On December 2, 2019, EPA published proposed amendments to the CCR Rule that included new deadlines to cease waste receipt and initiate closure for unlined surface impoundments. The proposed amendments indicated all five Laramie River Station ponds would be required to cease accepting waste by August 31, 2020 (with a potential extension to November 30, 2020). On July 29, 2020, EPA released a final rule (Part A Rule), which established April 11, 2021 as the cease waste receipt deadline for unlined surface impoundments.

Basin Electric has substantially completed the implementation of a long-term compliance plan for its surface impoundments to meet the CCR Rule. Four surface impoundments have been retrofitted and are in compliance with the CCR Rule. The remaining surface impoundment is undergoing retrofit or closure activities.

On May 8, 2024, EPA published a final rule titled “Hazardous and Solid Waste Management System: Disposal of Coal Combustion Residuals from Electric Utilities; Legacy CCR Surface Impoundments” (the 2024 CCR Rule). The 2024 CCR Rule removes the exemption for inactive CCR surface impoundments at inactivate generation facilities and establishes regulations for CCR management units (CCRMUs). The 2024 CCR Rule becomes effective 180 days after publication. EPA has identified one surface impoundment at Basin Electric’s former WJ Neal Station as being regulated under the 2024 CCR Rule. EPA has also identified two specific CCRMUs – one at Antelope Valley Station and one at Leland Olds Station – as being subject to the 2024 CCR Rule. Basin Electric is in the process of determining a compliance plan for the 2024 CCR Rule at all facilities. However, the 2024 CCR Rule is subject to petitions for review in the D.C. Circuit Court of Appeals. In addition, EPA has issued a proposed rule extending certain deadlines in the 2024 CCR Rule and is reconsidering the 2024 CCR Rule. The D.C. Circuit Court of Appeals litigation is being held in abeyance so that EPA can complete its reconsideration. Basin Electric considered this matter and currently have not made an accrual for this and is unable to predict what cost, if any, may be incurred to comply.

EGU MATS RULE—On May 7, 2024, EPA published a final rule titled “National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review” (EGU MATS Rule). The EGU MATS Rule eliminates the lignite subcategory for mercury emission limits, lowers the filterable particulate matter limits, and requires all units to install a particulate matter continuous emissions monitoring system. Basin Electric is in the process of determining a compliance plan for the EGU MATS Rule at all facilities, though Basin Electric has been granted a presidential exemption granting a 2-year extension to the compliance deadline. However, Basin Electric, other industry, and several states have filed petitions for review in the D.C.

BASIN ELECTRIC POWER COOPERATIVE AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS, Continued

Circuit Court of Appeals, which is currently being held in abeyance. On February 24, 2026, EPA published a final rule that repeals the more stringent standards in the EGU MATS Rule and reinstates the former standards. On March 30, 2026, a coalition of environmental groups filed a petition for review in the D.C. Circuit Court of Appeals challenging the repeal. Basin Electric considered this matter and currently has not made an accrual for this and is unable to predict what cost, if any, may be incurred to comply.

GHG RULE—On May 9, 2024, EPA published a final rule titled “New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Electric Generating Units” (GHG Rule). As part of this rulemaking, EPA also repealed the Affordable Clean Energy Rule.

For new sources, the GHG Rule establishes performance standards for three categories of natural gas generation: low load, intermediate load, and base load. These new source performance standards apply to all combustion turbines that commenced construction on or after May 23, 2023. The standard for low load facilities is based on the use of lower emitting fuels. The standard for intermediate load facilities is based on highly efficient simple cycle technology with best operation and maintenance practices. The standard for base load facilities is divided into two phases. For phase one, the standard is based on highly efficient combined cycle generation with best operation and maintenance practices. For phase two, which applies beginning January 1, 2032, the standard is based on phase one with the addition of 90 percent capture of CO₂.

For existing sources, the GHG Rule establishes emission guidelines for two categories of coal-fired electric generating units (EGUs): medium-term and long-term. EGUs that permanently cease operation before January 1, 2032, are exempt. The emission guidelines for medium-term facilities – operating on or after January 1, 2032, and ceasing operating by January 1, 2039 – are based on co-firing 40 percent natural gas. The compliance date for medium-term facilities is January 1, 2030. The emission guidelines for long-term facilities are based on 90 percent capture of CO₂. The compliance date for long-term facilities is January 1, 2032. States must submit plans setting standards for existing sources using these emission guidelines and incorporating other factors.

Basin Electric is in the process of determining a compliance plan for the GHG Rule at all facilities. However, industry, and several states have filed petitions for review in the D.C. Circuit Court of Appeals. In addition, EPA issued a proposed rule that includes significant changes to the GHG Rule, and the D.C. Circuit Court of Appeals litigation is being held in abeyance so that EPA can complete its reconsideration. Basin Electric considered this matter and currently have not made an accrual for this and is unable to predict what cost, if any, may be incurred to comply.

REGIONAL HAZE— On December 2, 2024, EPA issued a final partial approval and partial disapproval of North Dakota’s and Wyoming’s Regional Haze plans. On January 31, 2025, Basin Electric filed petitions for reconsideration with EPA and petitions for judicial review of the disapprovals. The states and other industry have also filed similar petitions. For North Dakota, EPA disagreed with the state’s determination that no additional controls were required for Antelope Valley and Leland Olds. In particular, EPA disagreed with North Dakota’s consideration of visibility impacts. For Wyoming, EPA argued that the state should have done a four-factor analysis for PM. EPA has not proposed federal plans to replace the state plans. EPA has granted reconsideration of its decision of both states’ plans but has not yet issued new proposals. Basin Electric considered this matter and currently has not made an accrual for this and is unable to predict what cost, if any, may be incurred to comply.

LITIGATION— On November 7, 2019, McKenzie Electric Cooperative, Inc. (McKenzie), a Class C member of Basin Electric and a member of Class A Member Upper Missouri G&T Electric Cooperative, Inc. (Upper Missouri), filed a lawsuit in North Dakota State Court against both Basin Electric and Upper

BASIN ELECTRIC POWER COOPERATIVE AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS, Continued

Missouri. The complaint brought multiple claims against Basin Electric, some of which have since been dismissed. McKenzie's remaining claims against Basin Electric are: (1) breach of the wholesale power contract (WPC) between Basin Electric and Upper Missouri (either as an alleged three-tier contract among Basin Electric, Upper Missouri and McKenzie, or with McKenzie being a third-party beneficiary to the WPC) by including losses associated with Dakota Gas in rates; and (2) declaratory judgment that the WPC permits McKenzie to terminate its contract with Upper Missouri prior to the expiration of the contract. Summary judgment motions were argued in April 2025 and are currently pending before the court. In September 2025, the parties reached a non-binding settlement in principle, through which the parties agreed to a settlement of all claims and allegations related to the matter. The settlement in principle is contingent upon execution of a mutually acceptable settlement agreement and corporate and regulatory approvals, as applicable to each party. At this time, while a loss is reasonably possible, Basin Electric does not believe that the amount of loss can be reasonably estimated pending finalization of a definitive settlement agreement and therefore has not currently made any accrual for this matter.

FERC REGULATION—Effective November 1, 2019, Basin Electric met certain criteria making the cooperative subject to the jurisdiction of the FERC. In July 2020, Basin Electric began filing with FERC its wholesale power contracts and rate schedule A. FERC accepted Basin Electric's filings, subject to settlement and hearing procedures. Class A Member Tri-State Generation & Transmission Association, Inc. (Tri-State), Class C Members McKenzie, Minnesota Valley Electric Cooperative (Minnesota Valley), and Wright-Hennepin Cooperative Electric Association, and the Sierra Club opposed in several FERC dockets Basin Electric's rate schedule A filings with FERC on various matters. In particular, the Sierra Club argued that Basin Electric should not be allowed to recover costs in its rates relating to certain of its coal generation assets; McKenzie argued that Basin Electric should not be allowed to recover costs in its rates relating to Dakota Gas; and Tri-State argued that Basin Electric's calculation of rates for depreciation expense and transmission service are not just and reasonable. A hearing before an administrative law judge was held from August 28, 2023, to October 27, 2023, and a second phase from February 5, 2024, through February 7, 2024. An initial non-binding decision by the administrative law judge was issued in June 2024. In September 2024, Basin Electric filed a brief on exceptions to the initial decision. No final decision has been issued by FERC, and the case remains pending. On July 16, 2025, Basin Electric received financing under the Rural Electrification Act of 1936. Basin Electric subsequently filed a motion at FERC to dismiss the active rate proceedings on the basis that, pursuant to Federal Power Act (FPA) Section 201(f), Basin Electric is no longer a public utility subject to FERC rate regulation and also filed notices of cancellation of its rate schedules, tariffs, and other agreements. The motion to dismiss remains pending before FERC. On September 12, 2025, FERC issued an order accepting the notices of cancellation, finding that, due to Basin Electric's change of jurisdictional status, it is no longer required to maintain tariff records with FERC. The cancellation order has since been appealed by Tri-State to the D.C. Circuit Court of Appeals, and remains pending with the appellate court. Minnesota Valley has subsequently voluntarily dismissed its objections in this proceeding and withdrawn as a participant in the matter. In September 2025, Basin Electric and McKenzie reached a settlement in principle, through which McKenzie agreed to withdraw its objections to Basin Electric's rates in the FERC proceedings and withdraw from and dismiss any other FERC proceedings and/or appeals in which it had intervened against Basin Electric. The settlement in principle is contingent upon execution of a mutually acceptable settlement agreement and corporate and regulatory approvals, as applicable to each party. See also "Litigation" above. Basin Electric considered these FERC proceedings and currently has not made an accrual.

RUS FINANCING – On June 10, 2025, McKenzie filed with FERC a Federal Power Act complaint against Basin Electric. The complaint requests that FERC find that Basin Electric is not authorized to obtain financing under the Rural Electrification Act of 1936 and that FERC retain jurisdiction over Basin Electric notwithstanding Basin Electric receiving such financing. Basin Electric contests the allegations of the complaint, and further contests McKenzie's right to the relief requested under the Federal Power Act.

BASIN ELECTRIC POWER COOPERATIVE AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS, Continued

Basin Electric has filed an Answer to the Complaint and a motion to dismiss. No further action has been taken by FERC and the case remains pending. In September 2025, Basin Electric and McKenzie reached a settlement in principle, through which McKenzie agreed to dismiss with prejudice its FERC complaint. The settlement in principle is contingent upon execution of a mutually acceptable settlement agreement and regulatory approval, as applicable to each party. See also “Litigation” above. Basin Electric considered this FERC proceeding and currently has not made an accrual.

NORTHWEST RURAL PUBLIC POWER DISTRICT – On March 26, 2024, Northwest Rural Public Power District (NRPPD) filed with FERC a complaint against Basin Electric and Tri-State. The complaint requested that FERC find that NRPPD is permitted to withdraw its membership in Tri-State, terminate its wholesale electric service contract (WESC) with Tri-State, and that its withdrawal and termination is permissible under the wholesale power contract between Basin Electric and Tri-State. In December 2024, FERC issued its order denying the complaint, but finding that NRPPD’s withdrawal from Tri-State and termination of its WESC is not a breach of the wholesale power contract between Basin Electric and Tri-State. Basin Electric filed an appeal of the FERC order with the D.C. Circuit Court of Appeals and the matter remains pending with the appellate court. In April 2026, Basin Electric and NRPPD reached a settlement in principle, through which NRPPD will dismiss its pending appeal at the D.C. Circuit and the underlying FERC complaint. The settlement in principle is contingent on execution of a mutually acceptable settlement agreement and regulatory approval, as applicable to each party. Basin Electric considered this matter and currently has not made an accrual.

Additionally, NRPPD has filed a complaint against Basin Electric in federal district court in Nebraska. In its amended complaint, NRPPD seeks a declaratory judgment that Basin Electric and Tri-State are bound by the December 2024 FERC Order that NRPPD’s withdrawal as a member of Tri-State, and therefore as a Class C Member of Basin Electric, is not a breach of the wholesale power contract for the Eastern Interconnection between Basin Electric and Tri-State. NRPPD further claims that it is a third-party beneficiary of the wholesale power contract between Basin Electric and Tri-State, and that Basin Electric has breached its obligations to Tri-State under the wholesale power contract by failing to provide NRPPD with an exit fee. Additional claims were added against Basin Electric for tortious interference with contract, tortious interference with a business relationship, and tortious interference with a prospective business relationship. Basin Electric contests the allegations of the complaint and has filed a motion to dismiss, which remains pending with the court. In April 2026, Basin Electric and NRPPD reached a settlement in principle, through which NRPPD will dismiss the pending complaint. The settlement in principle is contingent on execution of a mutually acceptable settlement agreement and regulatory approval, as applicable to each party. Basin Electric considered this complaint and currently has not made an accrual.

19. RELATED PARTY TRANSACTIONS

Basin Electric provides wholesale electricity sales and other services to its members. Basin Electric had accounts receivable from its members related to member wholesale power agreements of \$202.4 million and \$191.4 million as of December 31, 2025 and 2024, respectively.

Other receivables include \$2.3 million and \$3.7 million as of December 31, 2025 and 2024, respectively, for amounts Basin Electric, as operating agent, and its subsidiaries, have billed to MBPP. Included in special funds on the consolidated balance sheets is Basin Electric’s advance to MBPP of approximately \$17.0 million at both December 31, 2025 and 2024.

BASIN ELECTRIC POWER COOPERATIVE AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS, Continued

CONTRACTUAL COMMITMENTS—Basin Electric provides and receives power, various materials, supplies and services to and from affiliates which are under the following agreements through 2026, except as noted below:

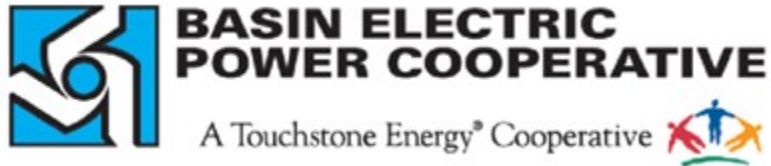
- **POWER SUPPLY**—Basin Electric provides all electric capacity, energy and transmission service needed to meet Dakota Gas's Synfuels Plant requirements under an agreement that extends through 2050.
- **SCREENED COAL**—Dakota Gas's Synfuels Plant provides screened coal to Basin Electric under an agreement that extends through 2037.
- **COAL SUPPLY**—Dakota Coal provides all coal requirements of Dakota Gas's Synfuels Plant and Basin Electric's AVS and LOS. This agreement extends through 2037.
- **ADMINISTRATIVE SERVICES**—Basin Electric provides various administrative and financial services to Dakota Gas, Dakota Coal, MLC and BCS.
- **LIME SALES**—Dakota Coal provides lime to Basin Electric's AVS and LRS.
- **LIMESTONE SALES**—Dakota Coal provides limestone to Basin Electric's LOS under an agreement that extends through 2040.
- **WATER SUPPLY**—Basin Electric provides water supply facilities for use by Dakota Gas's Synfuels Plant.
- **SALE OF NATURAL GAS**—Dakota Gas sells natural gas to Basin Electric for operation of utility gas generating plants and AVS (includes pipeline related costs).
- **USE OF TRANSMISSION ASSETS**—Basin Electric uses certain Dakota Gas transmission assets for a fee under an agreement that extends through 2047.
- **SALE OF FERTILIZERS, UREA AND DEF**—Dakota Gas sells fertilizers, urea and DEF to Basin Electric and MBPP for operation of power generation units.
- **PROJECT SERVICES**—Basin Electric provides the use of operational assets to Dakota Gas' Synfuels Plant.

BASIN ELECTRIC POWER COOPERATIVE AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS, Continued

Related party amounts that were not eliminated in consolidation in accordance with ASC 980 were billed as follows for the years ended December 31:

	<u>2025</u>	<u>2024</u>	<u>2023</u>
	(In thousands)		
Sales of goods and services to:			
Dakota Gas:			
Power supply	\$ 61,887	\$ 57,645	\$ 58,350
Administrative services	27,262	23,175	22,867
Water supply	2,339	2,482	2,541
Project and other services	491	369	221
Dakota Coal:			
Administrative services	2,535	2,457	2,410
Total	<u>\$ 94,514</u>	<u>\$ 86,128</u>	<u>\$ 86,389</u>
Goods and services provided by:			
Dakota Gas:			
Screened coal	\$ 67,942	\$ 59,711	\$ 50,637
Natural gas	14,241	11,524	14,164
Transmission and other misc. services	990	1,037	1,060
Fertilizers, urea and DEF	4,774	-	-
Dakota Coal:			
Coal supply	101,160	77,794	88,128
Lime	15,797	11,970	11,425
Limestone	2,570	2,709	2,804
Total	<u>\$ 207,474</u>	<u>\$ 164,745</u>	<u>\$ 168,218</u>

Various other intercompany management, administrative and financial services were performed, which were not significant.



Offer to Exchange
\$700,000,000 aggregate principal amount of
5.850% First Mortgage Obligations, 2025 Series A Bonds due 2055
for
\$700,000,000 aggregate principal amount of
5.850% First Mortgage Obligations, 2025 Series A Bonds due 2055
that have been registered under the Securities Act

PROSPECTUS

The Exchange Agent for the Exchange Offer is:

U.S. Bank Trust Company, National Association

By Mail:

U.S. Bank Trust Company,
National Association
Corporate Trust Services
P.O. Box 64111
St. Paul, MN 55164-0111

By Hand or Overnight Courier:

U.S. Bank Trust Company,
National Association
Corporate Trust Services
60 Livingston Avenue
1st Fl – Bond Drop Window
St. Paul, MN 55107

*For Information or Confirmation
by Email or Telephone:*

1-800-934-6802
cts.specfinance@usbank.com

Requests for additional copies of this prospectus and the letter of transmittal may be directed to the Exchange Agent at the address or telephone number set forth above. Beneficial owners also may contact their custodian for assistance concerning the Exchange Offer.

May 6, 2026
