BASIN ELECTRIC
POWER COOPERATIVE
A Touchstone Energy® Cooperative

December 5, 2019

Steve Kahl
Executive Secretary
North Dakota Public Service Commission
600 East Boulevard; Dept 408
Bismarck, ND 58505-0480

Re: Case No. PU-10-078 - Basin Electric Power Cooperative

Dear Mr. Kahl:

The purpose of this submittal is to provide the North Dakota Public Service Commission (NDPSC) with an updated decommissioning plan in the above-referenced case.

The updated decommissioning cost estimates are based on recent conversations with NDPSC staff. Most notably, the revised estimate reflects significantly increased disposal costs at the City of Minot landfill and an increase in the decommissioning cost estimate contingency amount from 10 percent to 20 percent.

Please contact me at 701.557.5495 or ksolie@bepc.com if you have any questions or concerns regarding this submittal.

Sincerely,

Kevin L. Solie

Kevin L. Solie, P.E.
Senior Environmental Compliance Administrator

/enclosure
cc: Casey Jacobson

5 PU-10-78 Filed: 12/5/2019 Pages: 17
Updated Decommissioning Plan with Cost Estimates

Basin Electric Power Cooperative

Kevin Solie, P.E.

BASIN ELECTRIC POWER COOPERATIVE

STATE OF NORTH DAKOTA
PUBLIC SERVICE COMMISSION

Basin Electric Power Cooperative **Case No. PU-10-078**
PrairieWinds and Minot Wind - Ward County, ND

DECOMMISSIONING PLAN

In accordance with North Dakota Administrative Code (NDAC) Chapter 69-09-09, Basin Electric Power Cooperative (Basin Electric) provides this decommissioning plan for the PrairieWinds ND1 and Minot Wind Projects in Ward County, North Dakota (collectively "PrairieWinds").

Basin Electric Power Cooperative Facilities

Basin Electric owns and operates two wind energy facilities in North Dakota. Minot Wind consists of two (2) NORDEX 1.3 megawatt (MW) turbines on 60-meter steel towers installed in 2002 and three (3) 1.5 MW General Electric (GE) turbines on 80-meter steel towers installed in 2009. PrairieWinds ND1 consists of seventy-seven (77) 1.5 MW GE turbines on 80-meter steel towers installed in 2009. PrairieWinds ND1 was permitted by the North Dakota Public Service Commission (Commission) Energy Conversion Site Compatibility Certificate No. 14. A decommissioning plan for the two facilities was submitted to the Commission in 2010. In June 2014, the Commission issued an order that delayed the financial assurance requirement for the turbines installed in 2002 until financial assurance was required for the adjacent 77-turbine project.

This decommissioning plan is filed in response to the Commission's rulemaking in PU-17-023, and is filed to update the existing decommissioning plan in the above-referenced matter as required under NDAC 69-09-09-07. The decommissioning plan is based on the proper treatment of the asset retirement obligation, consistent with generally accepted accounting principles or "GAAP" implemented by Basin Electric. The required elements for a decommissioning plan are presented below.

NDAC § 69-09-09-01(6)(a) - Anticipated Facility Life.

PrairieWinds turbines have an anticipated useful life of thirty (30) years or more. Upgrades based on new technology may allow the wind facility to produce efficiently and successfully well beyond this period of time. Within twelve (12) months after the facility or turbine reaches the end of its useful life, decommissioning shall begin and will be completed within twenty-four (24) months after the facility or turbine reaches the end of its useful life.

NDAC § 69-09-09-01(6)(b) - Decommissioning Cost Estimate.

In accordance with GAAP, Basin Electric Power Cooperative will assess, maintain, and recognize its asset retirement obligation, which includes decommissioning and restoration. The asset retirement obligation does not assume the recoupment of the salvage value associated with PrairieWinds components. The total cost of decommissioning and restoration at the end of the asset's life is estimated to be approximately $13,343,000. Exhibit A provides additional detail on estimated costs.

NDAC § 69-09-09-0l(6)(c) - Decommissioning Cost Estimate Method.

See attached Exhibit B.

NDAC § 69-09-09-01(6)(d) - Anticipated Manner of Decommissioning.

Decommissioning of turbines and towers includes dismantling of turbine components and transporting offsite. The costs and activities for the removal of the tower and wind turbine components, the substation, access roads, and the collection system have been evaluated, as follows:

Tower and Wind Turbine Components. The turbines are General Electric1.5 MW (80 turbines) and NORDEX 1.3 MW (two turbines) on steel towers. Activities have been estimated for dismantling the turbines, the tower sections and wind turbine blades. Removal of the tower wiring and transformer is also included. All components would be removed from the property.

Tower and Transformer Foundations. Tower and transformer foundations, conduits and connections will be removed to a minimum depth of four (4) feet below existing grade. The foundation sites will be graded to match surrounding contours and be restored to conditions that will support surrounding vegetation.

Balance of Plant. Aggregate base roads will be scarified, loaded, and removed from site to an appropriate location. The interconnection substation and operations and maintenance building would also be removed. Remaining subgrade will be decompacted and graded into the adjacent soils to the approximate original topography. This area will be covered with topsoil from the site and vegetation re-established.

Collection Svstem. The collection system terminations near the transformer will be removed to a minimum depth of forty-eight (48) inches below existing ground line. The underground collection system cabling is presumed to be left in place at its current depth of at least 48 inches below grade to the top of the lines.

Disturbed areas would be restored and reclaimed to the approximate original topography. Topsoil will be spread over the disturbed area at a depth similar to that in existence prior to the disturbance. The disturbed areas would be graded, top-soiled, and reseeded according to National Resource Conservation Service guidelines, unless the Commission approves otherwise.

NDAC § 69-09-09-0l(6)(e) - Effects on Present and Future Natural Resource Development.

PrairieWinds will continue operating during the project's useful life until which time the site will be restored in accordance with to the Commission's rules through the decommissioning process. PrairieWinds is not anticipated to materially impact present or future natural resource development during operations or decommissioning.

N.D. Admin. Code § 69-09-09-01(6)(f) - Detailed Plan of Financial Assurance to Ensure Decommissioning.

Basin Electric is a regional, consumer-owned, generation and transmission cooperative formed in 1961 to supply supplemental power to a consortium of rural electric distribution cooperatives. Basin Electric serves approximately 3 million consumers through 141 rural electric cooperatives across nine states. Basin Electric has assets of more than $7.3 billion and equity of approximately $1.4 billion.

Consistent with NDAC § 69-09-09-08, Basin Electric will provide financial assurance documentation after the tenth year of operation (no later than December 2019) to ensure sufficient resources for the decommissioning of PrairieWinds. Basin Electric meets the criteria for self-guarantee as allowed under NDAC § 69-09-09-08(5) and will utilize the self-guarantee financial assurance mechanism when required in December 2019.

Basin Electric's self-guarantee meets the requirements of NDAC § 69-09-09-08(5) because:

- Basin Electric has been in continuous business operation for at least five years.
- Basin Electric has a current rating in the "A" category rating as issued by S&P Global Ratings. The recent (April 2019) credit opinion is included as Exhibit C.

Consistent with NDAC § 69-09-09-08(6), the total amount of an outstanding self-guarantee for decommissioning does not exceed 25 percent of the owners' tangible net worth in the United States.

NDAC § 69-09-09-08(7) does not apply because no parent guarantee for decommissioning will be implemented.

N.D. Admin. Code § 69-09-09-06(3)(a) - Professional Engineer Certification.

I certify, as a Professional Engineer licensed in the state of North Dakota, that the information presented in the report is an accurate representation of the anticipated decommissioning costs for the Project, subject to the assumptions and limitations presented herein, and this report contains no intentional false statements or misrepresentations.

REGISTERED PROFESSIONAL ENGINEER
KEVIN L. SOLIE
PE-9488
DATE 12-5-2019
NORTH DAKOTA

Kevin L. Solie, North Dakota PE-9488

Exhibit A - Decommissioning Cost Estimate

Exhibit A

Estimated Decommissioning Costs for Basin Electric Wind Facilities

Decommissioning Activity PrairieWinds ND1 (77 turbines)	**Cost estimate**
Wind Turbine, Nacelle, Tower, and Electric Removal	$2,750,000
Blade and Foundation Removal	$1,549,000
Access Road Crushed Rock Road Surface Removal	$400,000
Removal and Disposal of Oils and Chemicals	$54,000
Hauling	$951,000
Disposal	$3,531,000
Topsoil and Seeding	$302,000
Total Net Cost	**$9,537,000**
Per Turbine Average Cost	**$124,000**

Decommissioning Activity Minot Wind (5 turbines)	
Five (5) Wind Turbines at $124,000 average cost	$620,000
Total Net Cost	**$620,000**

Decommissioning Activity - Balance of Plant (BOP) Substation, Operations & Maintenance (O&M) Building	
Mobilization and Demobilization	$52,000
Substation Removal	$263,000
Substation Hauling	$21,000
Substation Disposal	$80,000
O&M Facility Removal	$59,000
O&M Facility Hauling	7,000
O&M Facility Disposal	$26,000
Removal and Disposal of Oils and Chemicals	$7,000
Topsoil and Seeding	$2,000
Total Net Cost	**$517,000**

Decommissioning Grand Totals	
PrairieWinds ND1 (77 turbines)	$9,537,000
Minot Wind (5 turbines)	$620,000
Substation and O&M Facility	$517,000
Subtotal	**$10,674,000**
Owner Indirect Cost (5%)	$534,000
Contingency (20%)	$2,135,000
Grand Total	**$13,343,000**
Per Turbine Average Cost (includes BOP and contingency)	**$163,000**

Exhibit B - Decommissioning Cost Estimate Method

Exhibit B

Decommissioning Cost Estimate Method

Burns & McDonnell Engineering Company, Inc. ("BMcD") was retained by Basin Electric to conduct a decommissioning cost evaluation ("Study") for the PrairieWinds Wind Project ("Project") in 2016. The purpose of the Study was to review the Project and to make recommendations regarding the decommissioning cost and plan for retiring the facility at the end of its useful life. The BMcD Study predates (and is at times inconsistent with) the PSC's decommissioning rules; accordingly, it cannot be used for as Basin Electric's decommissioning plan by itself. The study does, however, provide a decommissioning cost estimate methodology and serves as a starting point for developing the current decommissioning cost estimate.

The decommissioning costs include the costs to return the site to a condition compatible with the surrounding land, similar to the conditions that existed before development of the Project. Included are the costs to retire the power generating equipment that is part of the Project as well as the costs to retire the Project's balance of plant facilities. The decommissioning cost estimate methods are based on the following assumptions:

1. All costs are adjusted to 2018 dollars.

2. The decommissioning estimate is based on the requirements specified in the Basin Electric wind lease agreement (Lease Agreement) and the PSC's 2017 decommissioning rules. If there is conflict between the Lease Agreement and the PSC rules, the PSC rules take precedent.

3. An offsite landfill is assumed to be used for disposal of demolition waste. Based on discussions with a local landfill (City of Minot Landfill in Minot, North Dakota), the cost for disposal of debris and concrete is $30.00 per ton. The hauling distance to this local landfill is approximately 23.1 miles (or 46.2 miles roundtrip) from Project.

4. Fluids located within the turbine nacelle including oils, fuels, solvents and process chemicals are assumed to be drained and disposed of offsite as part of the decommissioning.

5. It is assumed that all containers and chemical storage tanks owned by the Facilities will be drained and the material disposed of prior to demolition. These costs are excluded from the estimate.

6. All underground equipment including structures and foundations will be removed to a depth of four (4) feet in accordance with PSC rules and as specified in the Lease Agreement.

7. Structures or foundations greater than four (4) feet below grade will remain and are excluded from the decommissioning estimate.

8. Collector and communication cables are assumed to be located at least four (4) feet below grade and will be left in place.

9. Access roads, onsite roads, parking areas, storage yards, crane pads and all other areas constructed from asphalt, concrete, gravel or compactable fill will be removed.

10. All waste material will be properly disposed of offsite.

11. Transformers will be removed and processed onsite. The cost to drain and dispose of the Project transformer oil offsite is included in the decommissioning cost estimate.

12. The disposal of oil within all 77 active padmount transformers is included in the decommissioning cost estimate. Additionally, the Project is assumed to have two (2) spare padmount transformers which are assumed to be stored without oil and are excluded from the drainage estimate.

13. The removal of the Project substation and substation equipment is included in the decommissioning cost estimate.

14. The Project has no permanent meteorological towers.

15. The Project has one (1) O&M building which includes a warehouse side and an office area with a total dimension of 135 feet by 50 feet (6,750 square-feet).

16. Cost estimates include five (5) percent indirect costs and twenty (20) percent contingency.

17. Market conditions may result in cost variations at the time of contract execution.

Exhibit C - S&P Global Ratings

S&P Global
Ratings

RatingsDirect®

Summary:

Campbell County, Wyoming Basin Electric Power Cooperative, North Dakota; CP; Rural Electric Coop

Primary Credit Analyst:
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Summary:

Campbell County, Wyoming
Basin Electric Power Cooperative, North Dakota; CP; Rural Electric Coop

Credit Profile		
US$150.0 mil solid waste fac rev bnds 2019 (Basin Electric Power Coop Dry Fork Sta Facs) ser A due 07/15/2039		
Long Term Rating	A/Stable	New
Basin Electric Power Cooperative		
Long Term Rating	A/Stable	Affirmed
Basin Elec Pwr Coop coml pap nts (sr unsecured)		
Short Term Rating	A-1	Affirmed

Rationale

S&P Global Ratings has revised its outlook to stable from negative and affirmed its ratings on Basin Electric Power Cooperative, N.D., and the following debt obligations:

- The 'A' issuer credit rating on the utility; and
- The 'A' rating on Basin's $500 million series 2017A first mortgage obligation bonds, its $925 million 2015 series C first mortgage obligation bonds, and its $150 million 2009 series A Campbell County, Wyo., solid waste facilities revenue bonds.

At the same time, S&P Global Ratings assigned its 'A' rating to the proposed $150 million series 2019A Campbell County solid waste facilities revenue bonds. Basin plans to apply bond proceeds to redeem the 2009 series A Campbell County bonds on their July 15, 2019, redemption date.

Campbell will issue the 2019A bonds for Basin. The county must apply to these bonds' debt service payments the funds it receives from the utility. The financing structure unconditionally obligates Basin to pay these bonds' debt service. In addition, the utility will issue a note to the county that provides it with a security interest in the utility's assets under its mortgage indenture. The county's security interest on the bonds will be on par with Basin's senior secured debt.

In addition, S&P Global Ratings affirmed its 'A-1' rating on the utility's commercial paper, in accordance with its "Methodology For Linking Long-Term And Short-Term Ratings," published April 7, 2017.

The outlook revision reflects Basin's demonstrated capacity to produce what we consider strong debt service coverage (DSC) despite ongoing significant financial losses at Dakota Gasification Co. (DGC), an affiliate company of Basin's electric utility. DGC losses persist despite cost cutting and the diversification of its product offerings. The losses reflect weak market prices for the synthetic gas and agricultural commodities the affiliate companies produce. Nevertheless, the consolidated Basin companies produced accrual DSC of at least 1.45x in recent years, after recording revenue deferrals. Stronger cash DSC that precedes revenue deferrals reflects funds available to mitigate increasing debt amortization requirements.

Based on utility projections that assume that natural gas prices remain within a narrow band and wholesale electric rates to members and Basin's operating revenues largely do not change, we calculated accrual coverage levels through 2023 that are similar to those of recent years. The utility also projects an improving leverage ratio during the forecast years. The projections assume DGC will continue to produce losses in that time.

Basin is a Bismarck, N.D.-based electric generation and transmission (G&T) cooperative. In 2017, it was the largest U.S. electric cooperative in terms of total energy sales and member energy sales. Its 18 Class A members supply wholesale electricity to nearly three million customers and 123 retail electric systems, whose service territories cover portions of eight states extending from the Canadian to Mexican borders.

The utility's members' markets are exceptionally large compared with those of many other cooperative G&T utilities. However, we believe Basin's significant exposure to its competitive businesses and the dominance of members' commercial and industrial loads dilute some of the positive attributes of the market's breadth. Furthermore, many of the utility's large electric customers are concentrated in cyclical industries such as oil, natural gas, coal, and derivative products, which present credit exposures.

The cooperative operates an electric system that serves contracted members. In addition, the company has five subsidiaries. Two sell commodities in competitive markets. Basin's principal subsidiary, DGC, converts lignite coal into pipeline quality synthetic gas and related commercial products, including carbon dioxide and nitrogen-based agricultural products. This subsidiary has posted losses for several years due to a cost structure that is vulnerable to low natural gas prices and agriculture-related commodity prices. The non-utility operations reported losses of $94 million in 2016, $87 million in 2017, and $398 million in 2018. About $300 million of the spike in 2018 was due to a write-down of DGC's nonfertilizer assets. Low natural gas prices and an abundance of generation from low-cost renewable resources also affect the electric utility's revenues from surplus electricity sales.

The cooperative issues debt to finance the electric system's and its subsidiaries' capital needs. A first-lien pledge of substantially all of its assets secures the long-term debt. S&P Global Ratings assesses financial strength based on the consolidated entities' performance. The utility also guarantees DGC's obligations.

Basin reported $4.6 billion of consolidated long-term debt and capital lease obligations and $570 million of short-term notes as of Dec. 31, 2018. In fiscal 2018, the cooperative earned $2.4 billion of operating revenues.

The ratings reflect our assessment of the following strengths:

- The benefits the utility's revenue stream derives from the extremely broad membership base.
- Management has been willing to increase rates to help mitigate its competitive businesses' weak margins. In 2018, the average member's wholesale rate for Basin's electricity was $62.3 per megawatt-hour, which was double 2008's. These rate adjustments responded to an amalgam of higher debt and operating costs, the effects of weather variability on electricity demand, and the unfavorable conditions in the competitive markets in which Basin sells surplus electricity, coal, synthetic gas, and the byproducts of its synthetic gas production. Management believes that

it will not need additional rate increases through 2028.

- The 2016 rate adjustments responded to accrual DSC of 1.1x in 2015. We calculated 2016-2018 accrual DSC that was considerably stronger, at least 1.45x in those years. Cash basis coverage was more robust because the accrual income statement was adjusted for revenue deferrals that the utility plans to use to manage increasing annual principal amortization requirements. Basin projects that annual principal payments will increase sharply. Calculating the 2019-2023 forecast years' DSC using the average annual principal payments of $151 million through 2047, coverage will be about 1.35x rather than 1.45x
- After paring its capital program to reflect projections of more modest load growth due to the softer oil prices producers are receiving in the Bakken region, Basin projects that debt balances will decline by about 7% through 2023 and debt to capitalization will improve to 72% from 78% at Dec. 31, 2018.
- Member revenues are contributing increasingly larger shares of operating revenues.
- The utility is reducing its reliance on coal-fired generation.
- Management responded to low prices for DGC's output by raising rates, implementing cost-control measures, and paring capital spending.

The ratings also reflect these credit weaknesses:

- Low natural gas prices and volatile prices for the agricultural commodities Basin produces as byproducts of its synthetic gas production eroded DGC's profitability and eliminated contributions that historically benefitted members' wholesale electric rates. Non-utility margins were negative in 2013-2018. Management cites the synergies the subsidiaries deliver to the utility as mitigating the operating losses' impact. We view the non-utility operations that produce persistent losses as a drag on consolidated financial performance.
- Basin re-amortized its debt portfolio in 2015, which significantly pushed debt maturities to later years. As annual principal amortization increases, we will track whether management's actions remain sufficient to support DSC at levels that compensate for the significant business risks that the utility's companies as a whole face.
- We consider the significant presence of industrial customers with businesses tied to oil, natural gas, and coal extraction as exposing Basin to the respective sector's cyclical trends.
- The utility reports that of its Class A members and two distribution cooperatives that Basin serves indirectly through another of its Class A members have requested information relating to the process and costs of severing their long-term contracts. It maintains that the requirements contracts do not permit buyouts and that it will not provide information in response to the requests.

Member electric revenues represented 65% of 2018's operating revenues, compared with 26% in 2008, when non-utility operations were profitable. Growth in member energy sales and rate increases fueled some of the uptick in members' relative contributions to operating revenues. But, the contraction in non-utility revenues was also an important factor influencing the relative contribution of member revenues.

We believe that the cooperative's nonmember competitive market activities, which include substantial sales of electricity, synthetic gas, and byproducts of synthetic gas production, distinguish it from many G&T cooperatives and do not provide the revenue security or predictability of member sales under long-term requirements contracts. In 2018, electric sales to nonmembers accounted for about 12% of operating revenues, synthetic gas sales accounted for about 6%, lignite coal sales from a subsidiary to Basin accounted for 5%, and synthetic gas byproducts sales accounted for 5%.

Long-term contracts between Basin and most of its member cooperatives extend through 2075. Three members' contracts expire in 2050. The contracts require members to purchase their electric needs from the utility beyond modest allocations of low-cost Western Area Power Administration hydroelectric energy and some other specified energy sources. We believe that these contracts do not provide the predictability ordinarily associated with long-term wholesale power sales contracts among generation cooperatives and their members, because non-utility operations expose about 30% of Basin's revenue stream to competitive markets that are beyond the scope of the board of directors' rate-setting authority. The contribution of member revenues improved significantly in recent years as member loads have grown with oil and gas exploration activity, the utility's rate actions that increased average wholesale rates significantly, and the declines in non-member revenues tied to soft markets.

Only one distribution member's rates are subject to state regulation. However, members' electric rates lack automatic power and fuel-cost tracking mechanisms.

Basin has been adding natural gas and wind capacity to reduce coal's relative contribution.

We believe that Basin exhibits sound liquidity. At Dec. 31, 2018, the utility reported $169 million of unrestricted cash and investments, representing about one-month's operating expenses, net of depreciation and amortization items. Although we view these cash balances as only adequate, more than $800 million of undrawn capacity under liquidity facilities at Dec. 31, 2018, raised available liquidity to more than six months' operating expenses.

Outlook

The stable outlook reflects the three most recent fiscal years' strong DSC and projections that we believe suggest a capacity to perpetuate those coverage levels. We believe these indicators show that Basin has the ability to temper its exposure to competitive wholesale markets, the effects of weather variability on electricity demand, its concentration in coal-fired resources, recurring unprofitable non-utility operations, and rising annual principal payment requirements.

Upside scenario

In light of the significant exposures Basin's businesses face, we do not expect to raise our ratings on the cooperative during out two-year outlook horizon.

Downside scenario

We could lower the rating if we consider the capacity to meet rising principal payments weak relative to the business risks the utility faces, whether due to exposure to weather patterns that erode customer electricity demand, unfavorable prices in volatile commodity markets, or capital projects. In addition, if the cooperative cannot respond to rising costs with rate adjustments, we could lower the ratings.

Ratings Detail (As Of April 25, 2019)		
Basin Elec Pwr Coop ICR		
Long Term Rating	A/Stable	Affirmed

Ratings Detail (As Of April 25, 2019) (cont.)		
Campbell Cnty, Wyoming		
Basin Elec Pwr Coop, North Dakota		
Campbell Cnty (Basin Elec Pwr Coop) solid waste facs rev bnds Basin Elec Pwr Coop-Dry Fork Stat Facs)		
Long Term Rating	A/Stable	Affirmed
Mercer Cnty, North Dakota		
Basin Elec Pwr Coop, North Dakota		
Mercer Cnty (Basin Elec Pwr Coop) CP		
Short Term Rating	A-1	Affirmed

Certain terms used in this report, particularly certain adjectives used to express our view on rating relevant factors, have specific meanings ascribed to them in our criteria, and should therefore be read in conjunction with such criteria. Please see Ratings Criteria at www.standardandpoors.com for further information. Complete ratings information is available to subscribers of RatingsDirect at www.capitaliq.com. All ratings affected by this rating action can be found on S&P Global Ratings' public website at www.standardandpoors.com. Use the Ratings search box located in the left column.