Approved September 13, 2016

Basin Electric Power Cooperative
Bismarck, North Dakota

Minutes of the Regular Meeting of the Board of Directors
August 9-11, 2016

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The Regular Meeting of the Board of Directors of Basin Electric Power Cooperative (the **Cooperative** or **Basin Electric**) was held at the headquarters building, Bismarck, North Dakota, beginning on August 9, 2016 at 1:00 p.m. CDT.

1. Call to Order

The meeting was called to order by President Wayne Peltier, who presided, and Secretary-Treasurer Gary C. Drost, who kept the minutes thereof.

2. Roll Call

After calling the roll, the Secretary reported the following Directors present:

Donald E. Applegate	Paul Baker
Leo Brekel	Gary C. Drost
Charles Gilbert	Mike McQuistion
Kermit Pearson	Wayne Peltier
Troy Presser	Roberta Rohrer
Allen Thiessen	

Said persons being all of the Directors of the Cooperative. Also present were Chief Executive Officer & General Manager Paul M. Sukut, Assistant Secretary Mark D. Foss and Basin Electric staff members Tracie Bettenhausen, Eric Carufel, Shawn Deisz, Tammy DeWitt, Mike Eggl, Elizabeth Erhardt, Chad Heck, Matt Greek, Steve Johnson, Kerry Kaseman, Mark Kinzler, Brian Larson, Tracy McBride, Gavin McCollam, Sally Meier, Deb Olafson, Diane Paul, Mike Paul, Dave Raatz, Mike Risan, Josh Rossow, Ken Rutter, Myron Singleton, Kevin Solie, Myron Steckler, Kevin Tschosik, Chris VandeVenter, Valerie Weigel and Michelle Wiedrich.

Also present were Dakota Gasification Company (**DGC**) Vice President David J. Sauer and Upper Missouri Electric Cooperative (**Upper Missouri**) manager Claire Vigesaa.

3. Approval of the Agenda

The Directors considered the agenda for the conduct of the business of the meeting. After an opportunity for the addition and deletion of items, it was moved by Director Drost, seconded by Director Baker and carried that the agenda be approved as presented/modified.

4. Approval of the Minutes

The minutes of the July 12-13, 2016 Regular Meeting of the Board of Directors were presented and after an opportunity for corrections, it was moved by Director Brekel, seconded by Director Pearson and carried that the minutes be approved as presented.

5. General Manager's Report

General Manager Sukut reported that tomorrow morning he and Mike Eggl will leave the Board meeting to attend a meeting among Minnesota Power Company (**MN Power**), Great River Energy (**GRE**) and North Dakota Governor Jack Dalrymple to begin the conversation that North Dakota coal is in trouble and to request the diversion of 50% of the interest from the North Dakota Legacy Fund into a North Dakota coal technology fund. This fund would be used to fund coal technology projects such as the Allam Cycle. He was not optimistic due to the state's $310 million tax revenue shortfall and resulting budget cuts. Later in the week, Mike Eggl and Dale Niezwaag will attend a meeting in Washington, DC with Department of Energy (**DOE**) Secretary Ernest Moniz, Senator John Hoeven and Minnkota Power Cooperative (**Minnkota**) to discuss potential DOE funding for Minnkota's Tundra Project and an Allam Cycle demonstration project utilizing coal gasification.

6. Office of General Counsel Report

Senior Vice President & General Counsel Mark D. Foss provided an update on the status of legal matters concerning the Cooperative, including the Laramie River Station (**LRS**) Best Available Retrofit Technology (**BART**) litigation and the Clean Power Plan (**CPP**) litigation.

A. Proposed Bylaw Amendment - Director Conflict of Interest

Mr. Foss reported that in the course of preparing for the upcoming Bylaw Review Committee meeting, he came across the section of the bylaws addressing director conflicts of interest (Article IV, Section 7), the first sentence of which reads as follows:

"Section 7, Conflict of Interest. No person shall be eligible to become or remain a Director or to hold any position of trust in the Cooperative who is in any way employed by or financially interested in a competing enterprise or a business selling electric energy or supplies to any Member of the Cooperative."

As was the case with the indemnity bylaw provision that was modified last year, and based on his review of other electric cooperative bylaws, it was Mr. Foss' belief that this bylaw provision originates from the model Rural Electrification Administration bylaws and was likely drafted with distribution cooperatives in mind (hence the reference to selling energy or supplies to members).

He noted that it would make more sense if this provision precluded employment by or a financial interest in an enterprise or business doing business with the Cooperative and its subsidiaries as opposed to a business or enterprise doing business with the members of the Cooperative. He recommended that the first sentence of Article IV, Directors, Section 7, Conflict of Interest, of the Basin Electric Bylaws be revised as follows:

"No person shall be eligible to become or remain a Director or to hold any position of trust in the Cooperative who is employed by or holds a direct or indirect financial interest in any supplier, contractor or consultant that does business with the Cooperative or its subsidiaries. ~~in any way employed by or financially interested in a competing enterprise or a business selling electric energy or supplies to any Member of the Cooperative.~~

Director Drost suggested maintaining the existing language but eliminating the words "to any Member of" so that it would read as follows:

"No person shall be eligible to become or remain a Director or to hold any position of trust in the Cooperative who is in any way employed by or financially interested in a competing enterprise or a business selling electric energy or supplies to ~~any Member of~~ the Cooperative."

Mr. Foss will propose this revision to the Bylaw Review Committee.

B. CFC District 6 Meeting

Mr. Foss reported that the National Rural Utilities Cooperative Finance Corporation (**CFC**) combined Districts 5 and 6 member meeting will be held at the Hilton Minneapolis on Wednesday, September 21, 2016 immediately following the National Rural Electric Cooperative Association's First General Session.

In addition to hearing a financial update on CFC, registered delegates in District 6 will elect a nominating committee that will be responsible for selecting nominees for the CFC District 6 board seat (Position M) that will open in 2018 and elect a candidate to fill the District 6 director seat (Position D) that will open in 2017.

After discussion, it was moved by Director Pearson and seconded by Director Gilbert that Directors McQuistion and Presser serve as delegate and alternate, respectively, to this meeting. The motion carried.

7. Operations Report

Senior Vice President of Operations John Jacobs reported that there was one medical treatment and no Days Away, Restricted or Transferred (**DART**) incidents during the month.

He provided bus-bar costs for the coal-fired fleet, reviewed the equivalent forced-outage rate trends for the past 24-month period and reviewed the year-to-date running plant capacity factors for the coal units. July generation for the owned and operated Basin Electric fleet came in at 2,562,419 MW compared to the budget of 2,683,237 MW, which is 4.5% under budget for the month. Year-to-date generation is 5.5% below budget.

Individual availability at the Antelope Valley Station (**AVS**), Dry Fork Station (**DFS**), Leland Olds Station (**LOS**) and Laramie River Station (**LRS**) and capacity factors for the coal-based generation stations in July were as follows:

Unit	Availability	Running Plant Capacity Factor(net)	Unit Rating	Comments
AVS #1	89.46%	96.9%	450 MW	Forced outage on 7/7 for low furnace pressure. Had water wall leak for several weeks before this. Close to boiler pressure indicator which gave a false indicator which tripped the unit.
AVS #2	100%	97.3%	450 MW	
DFS	100%	100.49%	386 MW	
LRS #1	100%	83.97%	570 MW	

LRS #2	99.54%	82.73%	570 MW	Forced outage on 7/27 for loss of primary air fan 2B.
LRS #3	100%	82.47%	570 MW	
LOS #1	87%	97.89%	221 MW	Scheduled outage 7/28 for recirculating boiler feed pump repairs; forced outage 7/31 for repair of booster fan inlet damper.
LOS #2	85%	93.17%	448 MW	Forced outage on 7/4 for failed forced-draft fan expansion joint; scheduled outage 7/26 to tie-in Unit #1 batteries.

He then presented photographs and discussed the AVS 2B circulating water pump repair.

Mr. Jacobs thanked Anine Lambert for preparing the host agreement for the Integrated Test Center that Mr. Sukut will soon execute. A tech advisory group has been established to discuss the large test center and how evaluations of the proposals will be conducted for technologies to come in and test. The five smaller test centers will be dedicated to the XPrize contestants. If you read through the news stories, you will discover they are looking at a variety of some very different technologies.

Regarding the large test center, the most current discussion is the potential of splitting it into two 10 MW test centers depending on how the technology proposals come in. Governor Mead looks at this as a way to help enhanced oil recovery and to be able to test technology that has been proven at least at 5 MW or greater that now needs to scale up.

XPrize has narrowed its applications to 47 different teams/technologies. Of concern to the Cooperative are the people coming onto the plant site and items/chemicals being brought on site. We will need to conduct background checks and material safety data sheet checks so we know exactly who and what materials are on-site and so there are no Homeland Security issues. All cost is at the state of Wyoming's expense. We have been asked to quote the cost to construct one single 50-foot stainless steel chimney to accommodate handling 20 MW of flue gas. Permitting will be required from the state. Splitting the large test center will be an additional cost, but everything else is the teams' responsibility. We will not take any actions that would require opening any of our permits.

We had five responsive bidders to perform the test center work and the bids ranged from $5.9 million to $6.1 million.

He then presented photographs and discussed the tie-in of the LOS Unit #2 batteries.

A. Distributed Generation Update

Distributed Generation Manager Kevin Tschosik reported natural gas prices for the distributed generating facilities (Groton Generating Station (**Groton**), Culbertson Combustion Turbine (**CT**), Wyoming Distributed Generation (**WDG**), Spirit Mound Station (**SMS**), Deer Creek Station (**DCS**), Pioneer Generation Station (**PGS**) and Lonesome Creek Station (**LCS**) increased slightly during the month. July generation at the distributed generation facilities was as follows:

Unit	Monthly Availability	Monthly Generation	Unit Rating	Comments
Culbertson CT	96.17%	8,737 MW	100 MW	Ran for load demand.
DCS	99.13%	79,420 MW	300 MW	Ran for generation.
Groton #1	99.66%	3,679 MW	100 MW	
Groton #2	53.96%	5,261 MW	100 MW	Nox water pump failed inside the package and leaked and sucked into vapor extractor into hydraulic system. Had to be cleaned up.
LCS #1	55.92%	12,680 MW	45 MW	Boroscope inspection.
LCS #2	99.14%	23,731 MW	45 MW	Ran for load demand and reliability.
LCS #3	98.24%	23,946 MW	45 MW	Ran for load demand and reliability.
PGS #1	99.14%	11,228 MW	45 MW	Ran well for load demand and some reliability.
PGS #2	99.9%	10,892 MW	45 MW	
PGS #3	98.94%	9,464 MW	45 MW	
SMS #1		0 MW	60 MW	Did not run.
SMS #2		0 MW	60 MW	Did not run.
WDG		51 MW	45 MW	

The LCS #1 high-pressure turbine engine has 8,892 fired hours. The June 2016 engine boroscope inspection noted major rubs in the stage 1 high-pressure turbine shrouds, major tip rubbing, minor coating losses, some major blade tip wear and pockets of heat blistering. The engine damage was found in time to prevent damage to the low-pressure turbine. He presented a diagram and photographs of the LMS 6000 gas turbine and photographs of the damage.

Repair options were: (1) on-site high-pressure turbine exchange which would take eight days and cost approximately $1.6 million; (2) send the engine to Houston for the high-pressure turbine repairs which would take 90 days and cost approximately $2.2 million for just the first stage; or (3) purchase a new high-pressure turbine which would cost approximately $3.6 million. Mr. Tschosik reported that the first option, the exchange, was selected. An insurance claim has been filed with FM Global. He reported that the repair will need to be approved by the Basin Electric Board of

Directors, at which point this will become a capital project as it's an equipment replacement.

He noted that the combustor was competitively bid and prices came in lower than expected from PW Power Systems (formerly Pratt Whitney). Eventually, we will have to buy new liners and transition pieces under a separate capital project request.

During July, PGS #1 ran 401.18 hours in synchronous condensing mode and LCS for zero hours. The WDG had 15 west-side spinning reserve events for the month.

PrairieWinds ND (PWND). Blade repairs have begun. Annual maintenance is 52% complete. Wind turbine D60 was hit by lightning three times during the month. He presented photographs of the lightning damage.

PrairieWinds SD (PWSD). The A9 WTG gearbox planetary gear failed. It is under warranty so will be repaired at no cost to the Cooperative.

The east-side peak occurred on July 9, 2016 at hour ending 1900 hours. At that time, wind generation was as follows:

Wind Project	Load Factor during the Peak	Capacity Factor		Project Total
		Month	YTD	
Baldwin	20 MW	37%	43%	99 MW
Campbell County	72 MW	37%	37%	88 MW
Day County	96 MW	43%	49%	99 MW
Edgeley	13 MW	21%	30%	40 MW
Highmore	29 MW	34%	39%	40 MW
Iowa Wind	10 MW	23%	39%	45.1 MW
Other Projects (Chamberlain & Pipestone)	0 MW	41%	52%	3.4 MW
PWND	0 MW	31%	42%	123 MW
PWSD	148 MW	36%	44%	162 MW
Wilton	24 MW	33%	40%	99 MW
Total Monthly Wind Generation	412 MW	34%		800 MW maximum
Average Capacity Factor		34%	42%	

Mr. Tschosik invited the directors to the DCS employee family night which will be held on August 17th at 5:00 p.m. at Pioneer Park in Brookings, South Dakota.

B. LRS Plant Update

LRS Plant Manager Brian Larson introduced LRS Plant Superintendent Myron Singleton, who reported that 41% of the LRS workforce has zero to five years of service and 17% has six to 10 years of service. He noted that over the years, a majority of the safety incidents at LRS have involved employees with less than 10 years of service, so safety is being stressed. There were no DART or Office of Safety and Health Administration injuries during July.

He reviewed compliance statistics for NO_X, opacity and SO_2, as well as the percentage of SO_2 of allowances consumed for 2016. LRS has never had a NO_X exceedance and the limit is now 75% lower than when the plant was first commissioned. After installation of the selective catalytic reduction (**SCR**) and selective non-catalytic reduction (**SNCR**) equipment, the NO_X limit will be 90% lower than when the plant was first commissioned.

July generation was 1,055,073 net MWh compared to the budget of 1,087,759 net MWh. He also reviewed net heat rate, availability, equivalent availability, forced outage rate and equivalent forced outage rate for the month and year-to-date. He discussed projects completed during the April 16 to May 30 outage and outages planned through 2019, mainly for installations related to the SCR and SNCRs.

The Grayrocks Reservoir is 101.4% full at 4,404.4 feet Mean Sea Level. The LRS stockpile is estimated to contain 1,610,927 tons which is sufficient for 67 days for all three units at full load.

Mr. Singleton presented photographs and discussed the old bulk laydown yard before and after it was demolished in preparation for construction of the SCR project, progress on the new bulk warehouse, installation of the new Unit #2 sootblowers and the new electrical building for the Unit #2 circulating water system.

8. Communications & Administration Report

Senior Vice President--Communications & Administration Mike Eggl reported that the 2016 Fall Fly-In (Washington, DC) cooperative reception is scheduled for Tuesday, September 27, 2016 from 6:00 p.m. to 8:00 p.m. in Senate Hart Room 902.

He reported there will be a meeting on August 11th among DOE Secretary Ernest Moniz, North Dakota Senator John Hoeven, the North Dakota Lignite Energy Council, the Energy & Environmental Research Center, ALLETE and Basin Electric, which will provide an opportunity to update Mr. Moniz on the meeting with his staff in May, discuss ongoing research and the potential construction of an Allam cycle unit using coal gasification, the funding needs and timeline, request contacts at DOE and strategies for long-term funding needs for Allam projects and reinforce Senator Hoeven's support for advanced coal technology development.

Mr. Eggl reported on the August 2-4, 2016 North Dakota Special Legislative Session to make adjustments to the budget due to the $310 million shortfall in tax revenues.

Legislative Representative Chris VandeVenter discussed the 2016 presidential, Senate and House of Representatives elections.

Mr. Eggl reported he had received no comments on Board Policy #8, Guiding Principles, Protocols and Practices. After discussion, it was moved by Director Drost, seconded by Director Brekel and carried that the following Resolution be adopted:

R01.08-09-16 RESOLVED, the Board of Directors reaffirms Board Policy #08, Guiding Principles, Protocols and Practices (et al.) for Basin Electric Power Cooperative in the form presented to this meeting, superseding and replacing all previous versions of this policy.

Mr. Eggl noted that approval of Board Policy #8 completes the review of the Board Policies. The DGC board policies will now be reviewed.

He asked the directors to think about whether the Board wanted to give out the Cornerstone and/or Cooperative Spirit Awards this year and noted that the Board chose not to give an award last year.

The annual meeting theme is "Strong and United" and is scheduled for November 8-10 at the Bismarck Events Center with a social at the North Dakota Heritage Center.

Mr. Eggl reported the "Power of Human Connections" traveling exhibit at the North Dakota Heritage Center that was created by the Basin Electric Communications Department won an interpretive Media Award (Interior Exhibit) from the National Association for Interpretation. This is a prestigious international award.

A. Quarterly IS&T Update

Budget. Vice President of Information Systems & Technology (**IS&T**) Mark Kinzler reported that new processes were implemented to track costs and senior staff approval is now required for all unbudgeted information technology requests. He reviewed IS&T's year-to-date targeted budget versus actual target variance. Unbudgeted requests that were approved by senior staff total $1.8 million and were for new software critical to business, additional licenses of current software, contracted services to implement critical software and support the Business Units and additional desktop hardware and licenses.

NERC CIP. He reported that meeting the North American Electric Reliability Corporation's (**NERC**) Critical Infrastructure Protection (**CIP**) standards was a major staff major effort during the first half of 2016 and included 11 standards, 130 requirements/subrequirements, 35 Basin Electric program documents, as well as one CIP senior manager, one CIP program manager, 12 CIP project managers, 60 CIP subject matter experts, 950 CIP-designated employees and in-scope assets include tracking of 220 facilities, 13 medium impact facilities and 180 low-impact facilities.

Governance. The Administrative Bulletins were reviewed and edited for incorporation into the Employee Guidelines. IS&T policies are being created and updated so there is a single set of policies to cover the entire fleet. Governance is also currently being reviewed by Human Resources.

Consolidation. Mr. Kinzler reported that platform consolidation has resulted in a savings of $650,000. Windows 2003 and SQL 2005 are being upgraded. Eleven Windows 2003 servers remain to be upgraded.

Staff is reviewing opportunities to consolidate and standardize software. The year-to-date savings is $442,487. Next steps include identification of product overlaps, communication with the Business Units and working with users on the potential consolidation. Staff is also currently evaluating a fleet management software.

Business Continuity. Staff is validating the IS&T Disaster Recovery Plan, which coincides with platform and software consolidation. Tier 0 of the base recovery plan is being finalized and staff is beginning the next phase of Business Critical Applications.

Staff is coordinating with the Business Unit Coordinators and performing recovery tests of various systems.

Minding the Store. Mr. Kinzler then reported on the migration of member cooperatives' exchange email, SharePoint Team Sites, custom developed application rewrite, multiple system upgrades, installation and configuration of new software products and the IS&T audit by Deloitte & Touche.

9. Risk Management Report

Manager of Commodity Risk Kerry Kaseman reported that the average natural gas hedged price for 2016 is $2.33/dekatherm (**dkt**), increases each year and for 2021 is $3.22/dkt. He reported on the current hedge position for natural gas in storage.

He reviewed the Ventura Forward Curve which, as of August 1, 2016, starts at $2.91/dkt for 2016, climbs to $3.08/dkt for 2017, drops to $2.93/dkt for 2018 and 2019 and increases to $3.03/dkt for 2020.

July settled financial hedges for natural gas resulted in a gain of $471,898. He reviewed the Mark-to-Market (**MTM**) loss of ($341,000) for natural gas.

He reviewed the current hedge position for west surplus sales, which reflected a 2016 average on-peak hedge price of $25.71/MW and off-peak hedge price of $18.17/MW.

The current hedge position for east purchased power was $22.94/MW on peak and $22.25/MW off peak.

He reviewed the Palo Verde On-Peak Forward Curve which, as of August 1, 2016, started at $30.18/MW for 2016, increased to $31.13/MW for 2017, dropped to $30.93/MW for 2018, climbed to $31.55/MW for 2019 and ended at $32.08/MW for 2020.

He reported that July settled financial hedges for 45 MW of power resulted in a loss of ($132,546).

He reviewed the MTM power gain of $288,000, which does not include the negative $17.2 million MTM on a long-term physical contract.

He reviewed the current hedge position for diesel, which reflected an average hedged price of $2.17 per gallon for 2016, $2.43 per gallon for 2017 and $2.56 per gallon for 2018 and showed little change month to month. He reviewed the Energy Information Agency's on-highway diesel price projections which dropped twenty cents since July 1st and, as of August 1, 2016, started at $2.24 per gallon increasing to $2.75 per gallon for December 2018. The July settled financial hedges for diesel resulted in a gain of $19,705 on a 77,000-gallon diesel hedge. As of July 31, 2016, the diesel MTM was a gain of approximately $50,000.

The aggregate settlement for all commodities for the month was $359,057 and $114,702 year-to-date, which does not include the MTM gain/loss on premiums and ineffective hedges. He then reviewed the ($3,000) loss on MTM for all commodity hedges, liquidity position and credit exposure by Moody's Investor Service credit ratings.

10. Recess and Reconvention

At 4:05 p.m. President Peltier recessed the meeting until 8:00 a.m. August 10, 2016, at which time the meeting reconvened with President Peltier continuing to preside and Secretary Gary C. Drost continuing to keep the minutes.

11. Roll Call

After calling the roll, the Secretary reported the following Directors present:

Donald E. Applegate	Paul Baker
Leo Brekel	Gary C. Drost
Charles Gilbert	Mike McQuistion
Kermit Pearson	Wayne Peltier
Troy Presser	Roberta Rohrer
Allen Thiessen	

Said persons being all of the Directors of the Cooperative. Also present were Chief Executive Officer & General Manager Paul M. Sukut, Assistant Secretary Mark D. Foss and Basin Electric staff members Tracie Bettenhausen, Tanner Broderick, Andy Buntrock, Eric Carufel, John Ciz, Shawn Deisz, Tammy DeWitt, Mike Eggl, Elizabeth Erhardt, John Frank, Matt Greek, John Jacobs, Steve Johnson, Kerry Kaseman, Becky Kern, Mark Kinzler, John Klein, Matt Kolling, Chad Kuntz, Sharon Lipetzky, Tracy McBride, Gavin McCollam, Mary Miller, Deb Olafson, Diane Paul, Mike Paul, Curt Pearson, Dave Raatz, Mike Risan, Josh Rossow, Ken Rutter, Myron Singleton, Kevin Solie, Susan Sorensen, Myron Steckler, Kevin Tschosik, Chris Vizenour, Valerie Weigel and Michelle Wiedrich.

Also present were DGC Vice President David J. Sauer, Upper Missouri manager Claire Vigesaa and Mor-Gran-Sou Electric Cooperative (**Mor-Gran-Sou**) manager Don Franklund.

12. Marketing & Asset Management Report

Senior Vice President-Marketing & Asset Management Ken Rutter reported on the North Hub, Minnesota Hub and Palo Verde forward pricing, noting that on July 27, 2016, the United States set an all-time power burn record utilizing 40.7 billion cubic feet per day (**bcf/d**) of natural gas to generate electricity. The July average was 35.3 bcf/d with August forecasts showing 33.8 bcf/d. July's records were based on nationwide temperatures being two degrees above normal (79 degrees Fahrenheit). He noted that the Southwest Power Pool (**SPP**) prices didn't see the lift one might have expected with the higher gas prices and suggested that likely reflects the magnitude of wind generation in SPP.

Planned outages for refueling at nuclear plants will occur this fall. The fall of 2015 saw 30.9 GW down for maintenance, with this fall looking at only 23.1 GW. These outages are planned to start in mid-October and, if all goes according to plan, be back on line in mid-December. Sixty percent of the replacement generation is expected to come from gas-fired plants.

The July day-ahead average SPP load zone price was $24.67 and the July real-time average was $22.96. These pricing numbers represent the average around-the-clock market pricing and do not necessarily represent actual transacted prices.

West-side resources were online throughout the month with DFS derated as a result of high ambient temperatures. Volumetrically, in the day-ahead and real-time markets an average of 175 MW were sold in the on-peak hours and 220 MW were sold in the off-peak hours. This includes sales in the west and sales into SPP across the ties. He noted there is a limited depth to the market on the west side as well as limited transmission to move power around, hence we end up moving power to the east.

Wyoming Municipal Power Agency (**WMPA**) has advised it will execute a scheduling contract with Basin Electric when its current contract with Western expires.

Day-ahead on-peak sales achieved 87% of the PV Index while day-ahead off-peak sales achieved 80% of the PV Index.

Given the higher locational margin prices in July and no major plant outages, Basin Electric was primarily a net seller in the SPP and was able to achieve margins on selling surplus generation into the market. However, Basin Electric's surplus sales price was below the budgeted surplus sales price for the month.

Execution of 2017 Basin Electric Surplus Sales Hedge Plan. Of the targeted $27.2 million revenue, $15.5 million has been secured or roughly 57% of the plan. Of the targeted 1,058,800 MWh, 560,400 have been secured or 53% of the plan. If the remainder of the plan was filled at today's prices, the Cooperative would secure a revenue of $29.9 million versus the $27.2 million notional value of the plan.

Execution of 2017-2021 Basin Electric Natural Gas Hedge Plan. Of the targeted $95.0 million expenses in the plan, $73.7 million has been secured or roughly 78% of the plan. Of the targeted 32,346,620 mmbtus, 25,007,500 have been secured or 77% of the plan. If the remainder of the plan was filled at today's prices, the Cooperative would be securing an expense of $96.8 million versus the $95.0 million notional value of the plan.

13. Cooperative Planning Report

A. Nemadji Trio Energy Center

Vice President-Cooperative Planning Dave Raatz noted that, as reported last month, MN Power has requested a delay in execution of the Nemadji Trio Energy Center (**NTEC**) agreements until December 20, 2016 because they do not want to get ahead of the Minnesota Public Utilities Commission (**MN PUC**) regulatory process (additional resource analysis is required) and the uncertainty of MN Power load growth and MN Power subsidiary power needs. Takeaways from the MN PUC Order include beginning a competitive bidding process to procure 100 to 300 MW of installed wind capacity by the end of 2017; acquisition of solar additions of 11 MW by 2016, 12 MW by 2020 and 10 MW by 2025 (however the MN PUC also found that up to 100 MW of solar by 2022 is likely an economic resource) and MN Power must propose a demand response competitive bidding process and investigate an energy-efficiency competitive bidding process. MN Power stated that their wind studies should be completed by December.

MN Power must provide a project commitment decision by December 21, 2016. MN Power will bear all development expenses from July through December 2016, subject to true up if the project goes forward. MN Power will also seek an off-taker for a portion of its share of the NTEC via a five- to 15-year power purchase agreement in order to manage load risk. Follow-up discussions are being held at Basin Electric, among the partner teams and among the chief executive officers.

Mr. Raatz then reviewed the impact of the MN PUC's order on the NTEC development timeline.

It was staff's recommendation to continue project participation through December of 2016 and if the project agreements are not executed in December, to seriously evaluate other resource alternatives.

14. North Dakota Senator Heidi Heitkamp

North Dakota Senator Heidi Heitkamp joined the meeting and stated that the only way she sees the coal industry surviving is through the investment in technologies that will greatly reduce or eliminate the negative impacts of burning coal.

She noted her priority last year was to end the ban on U.S. crude oil exports. With passage of that legislation, the spread went from $7.00/barrel down to $1.00 to $1.50 so that the price difference now only reflects the difference in transportation costs.

She stated that in her view, coal is on its deathbed and quoted the old line: "If you are not at the table, you are on the menu". The coal industry was not at the table. Now it faces the challenge of low natural gas prices and is caught in the vise where on one side it is facing environmental restrictions such as the CPP and Regional Haze problems and on the other side it is trying to compete against very low wind and natural gas prices.

Where do we go with coal? The only way we survive is if we innovate and invest in technology. If we look at the average age of coal-fired generation, it's over 45 years. If you take all government stuff off the table, who is going to lend you money for a coal plant? No one. Coal is on life support. We started big with help from Basin Electric and the North Dakota Lignite Council and introduced an action plan and it was an attempt to look at all the technologies that we hope to learn more about in the next three to four years. Some of the best minds supporting these new technologies are people at DOE. People who care about climate and are most aggressive in the Senate are at the table now looking at how to invest in critical coal technologies. Although the treaty was never ratified, the United States was the only country that met the Kyoto Standards by switching to natural gas. They know that industrializing China and India are not going to stop using coal, so it comes down to how to use it more productively, economically and cleanly.

Clean coal initiatives are her highest energy priority. She said she learned a lesson from the fight to allow oil exports. No one thought it could get done. Step one is to work on the education piece and what developing those technologies in this country could mean to the global economy and environment.

She believes we've seen some cracks in both sides, but can we capitalize on them? Secretary Moniz is a good DOE secretary who understands this and his fossil team has been great for us to work with. Our problem is that the DOE isn't running energy policy in the United States, the Environmental Protection Agency (**EPA**) is. We will capitalize on getting every opportunity we can to educate and build political support for coal-based energy technologies.

She urged Basin Electric to look to the future and noted that we should be prepared to get into the transportation "fuels" business.

15. Cooperative Planning Report, continued

A. Nemadji Trio Energy Center, continued

Mr. Raatz noted that without MN Power, Basin Electric and Dairyland Power Cooperative (**Dairyland**) don't have a primary plant site. He noted that he has received many questions from the membership about the ability to build our own plant. MN Power said it would make a commitment by December 21 (at the meeting with CEOs and staff).

We asked if Basin Electric can participate more and who else might be at the table making the decisions. MN Power made no commitments at this time but during the last discussion, stated that it will visit about different options should it choose not to take the whole 300 MW and held firm that it will be the facility operator. If there is some sale of this resource, Mr. Raatz stated that it would be nice if the MN Power sale was through a power purchase agreement because it would not give the newcomer a seat at the table. Mr. Raatz stated that if we wait until December and the NTEC project falls through, there will still be enough time to proceed on a project of our own although the project economics would likely not be as favorable as the NTEC project.

Mr. Sukut reported that during the CEO discussion last week, MN Power was optimistic that it could get the NTEC project through the regulatory process. Dairyland also indicated it may have additional NTEC power that Basin Electric could purchase. Basin Electric has more need for this power than the other entities because we have more than 350 MW projected shortfall in the Midwest Independent System Operator (**MISO**) system if NTEC is not developed. Mr. Raatz noted that even with the NTEC project, Basin Electric projects that it will still be 50 MW short in MISO in the first year.

Should MN Power walk away from the project at the December 21 meeting, it will owe Basin Electric and Dairyland $500,000 each. Basin Electric, possibly with other utilities, would have to move quickly to identify another site (possibly in the Wisconsin area) and begin the permitting process which could take five to six years. We could purchase power, possibly from others, to get us another year down the road. The NTEC project is currently scheduled for commercial operation by December of 2022.

There have also been many questions from the members as to why we aren't just moving LOS into MISO. Based on the forecast, we will need resources in both MISO and SPP in the 2023-2024 time frame. If our forecasts are correct, even if we did divert LOS into MISO, we would still need more resources in SPP. From a power supply perspective, the economies of scale of the NTEC project are very attractive. If oil prices don't increase and drilling doesn't resume, we could then look at moving some baseload coal into MISO. There are also other purchase opportunities in MISO and SPP. At least now, based on forecast, we think we need the NTEC. It is a good partnership to minimize risk. Minnkota does have surplus generation going forward, but all surpluses are summertime.

He reiterated that the staff recommendation is to continue with the NTEC project through December 2016.

B. <u>Stanton Station Closure Announcement</u>

Mr. Raatz reported that on July 15, GRE announced plans to retire its Stanton Station by May of 2017. This unit had first fire on December 31, 1966, with commercial operation in 1967. This retirement will result in Basin Electric serving a greater amount of the GRE-fixing members' power requirements.

One of EVA's power supply studies indicated that, assuming $3.00 gas and even in a no CPP scenario, both GRE's Stanton Station and Minnkota's Milton R. Young Station would have to shut down no later than 2025. Because of regional haze and ozone rule requirements, these units will require significant capital improvements to operate. For the GRE-fixing members, whenever there is a retirement in the GRE resource base, a portion of the amount of the retirement load comes to Basin Electric. We should know the magnitude of this reduction by next week but it is probably in the 20-40 MW range.

GRE is taking the position that they don't know exactly how much power from the Stanton Station was used to serve that load and so it has to review the last three years of historical data. There is also discussion on whether these members are responsible for any of the shutdown costs. Once a resource goes out of the pool, the cost also goes out of the pool. While we are interested in serving this increased load, we hope to stay out of GRE member politics.

Director Presser reported that GRE has decided that it will wait for an increase in scrap iron prices and then will return the Stanton Station to a greenfield site. Also, with respect to bringing LOS into MISO, MISO has received a number of requests from wind projects to interconnect at the Stanton Station substation.

Mr. Raatz noted that there is SPP transmission between the LOS generator and how you'd get to MISO (at the Stanton Station substation), so there would either be a pancaked wheeling charge or you would need to construct a separate short transmission line to directly interconnect with MISO. It's not something you could do very quickly or cheaply and it does not change our projected need for power in 2024.

C. Resource Analysis

Mr. Raatz reported that we have several consultants evaluating different aspects of resource development including the SPP Wind Analysis, a west-side regional transmission organization (**RTO**), CPP and jointly dispatch North Dakota generation (GRE, Minnkota and Basin Electric). It is possible that a generation cooperative could be formed among these three entities. A decision on an SPP wind purchase is required in the October/November time frame. Long-term economics are being studied. Staff continues to negotiate with the wind developers on getting transmission service arrangements as well as guarantees. We recently received a very favorable proposal from a third party.

The internal analysis includes identifying the assumptions and analysis to identify the preferred long-term power supply portfolio; identifying the least-cost long-term power supply portfolio to meet the requirements of the membership; establishing a long-term resource decision strategy timeline and developing an action plan as needed. Staff plans to present the information to the Board in December.

D. Managers Conference

Mr. Raatz reported that topics of discussion at the July managers conference included loads at risk, a review of DGC, rate recommendations to the CEO/GM and the members' Public Utilities Regulatory Policies Act (**PURPA**) assignment to Basin Electric.

Loads at Risk. A memorandum was sent to the Class A managers in which staff will request a conference call with each Class A member to identify specific loads at risk and work on the load forecasting process. An update will be provided to the Board in September. A membership strategy discussion will take place in late September or early October, with full Managers Advisory Committee (**MAC**) discussion in October. Interestingly, the managers and staff appear to be more concerned with consumer choice legislation than with self-generation. We are looking for a strategy, not special rates.

DGC Review. Staff was asked to conduct additional study of the DGC Synfuels Plant shutdown case, after which the Class A managers will be given the opportunity to ask additional questions. The matter will be reviewed further in September or October.

Rate Recommendation to CEO/GM. The managers' rate recommendation to the CEO/GM with respect to the Renewable Energy Rate was to extend the rate, exclude new member-owned projects from further applications, increase the cap from 10 MW to 12 MW and to evaluate which project applications are moving forward.

PURPA Assignment. The June 30 PURPA memorandum to the managers asked for: (1) review of the draft Petition and Implementation Plan and to provide comments by August 1, 2016; (2) a board resolution adopting the Implementation Plan by September 1, 2016; (3) public notice in the official county newspapers during the fall of 2016; and (4) filing with the Federal Energy Regulatory Commission (**FERC**) once the previous steps have been completed.

Mr. Raatz noted that should distribution cooperatives request that their PURPA assignments be rescinded prior to filing, we will not include them in our request to FERC. If a member made such a request after FERC has approved the assignment, while Basin Electric could not stop the member from filing with FERC to reverse the assignment, it would not be in the best interests of Basin Electric and its members to rescind these assignments.

16. Engineering & Construction Report

A. Project Funding Chart

Senior Vice President-Engineering & Construction Matt Greek reported that six Basin Electric contracts totaling $31.5 million would be presented for approval this month. He presented the list of all current major projects along with the approved budget amount, total dollars committed and completion dates.

B. LOS Bottom Ash Dewatering & Process Water Recycling Project Budget Amendment

Project Manager Josh Rossow reported that in April 2015, EPA finalized the Coal Combustion Residuals (**CCR**) rule and staff from headquarters and LOS determined the best course of action was to close ash ponds II and III. To avoid extensive groundwater monitoring, by October of 2015, bottom ash could no longer be put into the ground and the pond must be capped and closed by April of 2018.

In September 2015, EPA finalized the Effluent Limitations Guideline (**ELG**) rule and, starting in November 2018, bottom ash water can no longer be discharged into the Missouri River.

In October 2015, a temporary/interim dewatering system was put in place and we discontinued putting ash in the pond. In January of 2016, the Board authorized $45.6 million for a permanent solution for recycled water at the plant. In April 2016, a CCR provision requiring pond closure was remanded and vacated by the courts, so pond closure was no longer required by April of 2018, which gave us an extra year of time.

The approval for a Bottom Ash Dewatering and Process Water Recycling project will enable ash transport waters to be captured and reused instead of being discharged to the ash pond. The project will also change the way wastewater flows are managed so that the existing bottom ash ponds can be closed by November of 2018.

The Board approved expansion of the coal pond in July of 2016 for $3.9 million. Coal fines in coal pile storm water runoff settle out before being discharged to the Missouri River. This project must be completed by November 2018 so as to cap and close ponds #2 and #3. The retirement obligation will be expensed. The project will be voluntarily completed by the end of 2019.

Project scope changes to the original bottom ash dewatering project scope include two submerged flight conveyors: one for beneficial use and one for waste ash; transport water recycle system of pumps and surge tank; and wastewater treatment system with parallel redundant trains.

The revised project scope includes one submerged flight conveyor for waste ash; interim system repurposed for beneficial use ash and redundancy; and wastewater treatment system with a single train.

He reviewed the project schedule and the budget amendment. The question was raised as to the costs associated with the closure of the ponds. It was noted that closure of the ponds will be required upon retirement of the plant and would be accounted for as an expense. As such, there is no capital cost in the project related to final remediation and closure.

Evaluation of the engineering, materials, equipment, construction, owner's costs, interest during construction and contingency of 15.1% results in a budget increase of $17 million, which does not include the cost of reclaiming the original pond, He noted this is the most economical fix. Should we continue using the interim system, we would still have to install cycle pumps and surge tanks -- which will be done as part of this project. For a little more cost, we are gaining more reliability.

Mr. Jacobs reported this project was on a compressed schedule when Jamey Backus presented it to the Board. We are trying to mitigate both ends of it. If we continue to run LOS, this project is required. We are keeping the project costs to a minimum. Mr. Greek noted that other options are still being reviewed, but if we don't do something to stop discharges into the Missouri River, LOS will have to stop operating. Part of the challenge is not being able to look at everything at once--we're forced to look at each issue in isolation: CPP, regional haze, CCR and ELG and not comprehensively. It's a difficult challenge. We've done enough with CPP that we're confident that we can and believe the cooperative will benefit from operating the LOS station beyond 2022 so we will need an adequate bottom ash and wastewater management system that complies with the recently announced regulations. A majority of the ash comes from Unit #2 because it is a cyclone boiler.

After discussion, it was moved by Director Presser, seconded by Director Brekel that the authorized budget for the Bottom Ash Dewatering and Process Water Recycling Project be amended from $45,576,530 to $58,513,962, an addition of $12,937,432. It was then moved by Director Thiessen and seconded by Director Drost that the motion be tabled until the next Board meeting. The motion to table carried.

C. <u>Pioneer Generation Station Phase III Update</u>

Mr. Rossow reported there was one property damage incident at this project in July. There were no environmental incidents.

Wärtsilä completed the 72-hour full-load reliability test on July 8 and performance and emissions testing is complete. Rachel Contracting is completing the finish grading, seeding and paving. He then reviewed project costs.

D. PGS Phase III Electrical Construction Contract Amendment

Mr. Rossow reported there had been a large amount of engineering changes after the contract award which resulted in delays and cumulative impacts to Saulsbury Industry's (**Saulsbury**) productivity. Saulsbury filed a claim. The project team agreed that Saulsbury was impacted, but not to the extent claimed. A settlement has been negotiated, contingent on Board approval. He reviewed the claim, the negotiated settlement and reported this would increase the electrical installation contract by $1,129,146. Mr. Rossow recommended approval of the contract amendment.

After discussion, it was moved by Director Gilbert, seconded by Director Presser and carried that the following Resolution be adopted:

R02.08-09-16 RESOLVED, that the authorized contract amount for the PGS Phase III Saulsbury Industries Electrical Installation contract be amended from $7,521,611 to $8,650,757, an addition of $1,129,146; and

BE IT FURTHER RESOLVED, that the CEO and General Manager, or his designee, be authorized to execute the contract.

E. LRS Spare Generator Step-Up Transformer Project Approval

Senior Electrical Engineer Chad Kuntz reported that the LRS Unit #3 generator step-up (**GSU**) transformer was taken out of service in November of 2015 due to the presence of acetylene which indicates arcing. The spare GSU was placed into service in Unit #3 in December of 2015. The assessment of whether to repair or replace the GSU was made in January/February of 2016. In March 2016, staff consulted with an independent transformer design expert, who recommended that the GSU be replaced due to age, design and inaccessibility of repair facilities as well as increased cost. He noted that our insurance carrier, FM Global, requires physical evidence of failure to support an insurance claim, which requires disassembly and inspection of this GSU.

In April, a request for purchase (**RFP**) was issued for disassembly and repair, but no bids were received for repair. An RFP was issued for replacement in May and four bids were received. The proposed project includes (1) disassembly of the GSU on-site which will be witnessed by engineering staff and FM Global to inspect for damage; (2) pursue the insurance claim, if possible; and (3) procure a new spare GSU transformer. Mr. Kuntz presented a photograph of the spare LRS Unit #3 GSU that was put in service. The estimated Class 3 project cost for replacement is approximately $5,749,450. He reviewed the estimated project schedule which calls for procurement starting this month, construction to start in January 2017 and the GSU to be in service in November of 2017. He recommended approval of the project.

After discussion, it was moved by Director Applegate, seconded by Director Brekel and carried that the following Resolution be adopted:

R03.08-09-16 RESOLVED, that the Laramie River Station Replacement Spare Generator Step-Up Transformer project presented to this meeting of the Board of Directors with an estimated cost of $5,800,000 ($2,451,660 Basin Electric cost) be approved; and

BE IT FURTHER RESOLVED, that the CEO and General Manager, or his designee, be authorized to execute the required documents.

F. LRS Spare Generator Step-Up Transformer Contract Award

Mr. Kuntz reviewed the spare transformer evaluated bids which ranged from $3,510,220 to $4,259,778 and recommended the contract be awarded to SMIT Transformers (**SMIT**), part of the SGB-SMIT Group, for $4,333,915. While not the lowest bid, the project team recommended SMIT because it is an industry-recognized quality manufacturer located in The Netherlands; it has provided several recent 345 kV transformers to Basin Electric (LRS, LOS, Charlie Creek and Judson); and it was the successful bidder for the 345 kV transformer for the Tande Substation, which recently completed successful Factory Acceptance Testing. He reported that in all instances, SMIT demonstrated exceptional quality and customer focus. Staff has no personal knowledge of the low bidder, Hitachi. The lead-time for delivery of the transformer is 12 to 18 months.

After discussion, it was moved by Director Gilbert, seconded by Director Rohrer and carried that the following Resolution be adopted:

R04.08-09-16 RESOLVED, that the Laramie River Station Replacement Spare Generator Step-Up Transformer contract presented to this meeting of the Board of Directors be awarded to SMIT Transformers in the amount of $4,333,915 ($1,831,946 Basin Electric cost); and

BE IT FURTHER RESOLVED, that the CEO and General Manager, or his designee, be authorized to execute the required documents.

G. Approval of Long-Range Engineering Plan

Mechanical Engineer Tanner Broderick presented and reviewed the 2017-2026 Long-Range Engineering Plan (**LREP**). Components of the LREP include major capital items and major maintenance items over and above routine outage-type maintenance, such as projects over $100,000 and major mobile equipment (regardless of the cost). Significant new generation and transmission facilities to meet load growth are not included in this document. The purpose of the LREP is to ensure safety, reliability, availability and environmental compliance while providing the best rate possible to the membership. The document is a planning tool for the financial forecast. He reviewed the LREP process.

The LREP for 2017-2026 reflects projects costing $1,092,000 and is broken down by facility as follows: $470 million for headquarters; $206 million for Transmission System Maintenance; $160 million for the peaking plants; $93 million for AVS; $79 million for LRS; $38 million for DFS; $27 million for LOS; $13 million for LRS TSM and $6 million for wind generation.

Large projects within the 2017-2026 LREP include the NTEC combined-cycle facility for $332.3 million (Basin Electric share), TSM Stegall DC Tie for $116.2 million, LRS Main Plant Dust Collection for $12.7 million (Basin Electric share), MBPP Microwave Equipment Upgrade for $9.9 million, AVS Generator Breaker Replacement Units #1 and #2 for $8.7 million, DFS Bottom Ash Non-Pneumatic Unloading System for $6.7 million and LOS Building Heating Boiler for $2.8 million. Mr. Broderick then recommended that the LREP be approved.

After discussion, it was moved by Director Drost, seconded by Director Pearson and carried that the following Resolution be adopted:

R05.08-09-16 RESOLVED, that the 2017-2026 Long-Range Engineering Plan is hereby approved.

H. Approval of 2017 - 2019 Construction Work Plan

Mr. Broderick then presented and reviewed the 2017-2019 Construction Work Plan (**CWP**) and noted that the CWP is only estimated cash flows for 2017 through 2019. It includes projected LREP capital projects and previously approved major projects. Approving the CWP is not authorization to proceed with these projects, but is a planning tool. In order to be constructed, the projects have to be authorized separately by the Board of Directors. The CWP is a road map for the next three years.

The CWP reflects total expenditures of $604.5 million and of that total, 47.8% of the CWP is for existing generation, 39.9% is for transmission facilities and 12.3% is for headquarters. Peaking facilities make up for 14.8% of the generation load.

The approximate percentages by project classification are: 97% is for capital projects and 3% is for mobile equipment. Projects under $100,000 account for 2% of the capital projects total. The approximate percentages by facility are: 10.7% are for LOS, 5.2% for AVS, 12.3% for headquarters, 2.5% for DFS, 14.4% for LRS, 39.9% for Transmission, 0.2% for wind and 14.8% for maintenance of peaking facilities.

He reviewed major items scheduled for each of the three years and noted that the CWP does not include any significant new generation and transmission to serve possible load growth. He then recommended approval of the 2017-2019 CWP. The CWP was required when the Cooperative was a Rural Utilities Service borrower; however, it is a good business practice and is used by the Financial Services staff for capital projects and by the Engineering Division.

After discussion, it was moved by Director Presser, seconded by Director Baker and carried that the following Resolution be adopted:

R06.08-09-16 RESOLVED, that the 2017-2019 Construction Work Plan is hereby approved.

17. Transmission Report

Senior Vice President of Transmission Mike Risan reported that as of July 31, 2016, the TSM Division has worked 85 days without a DART incident.

SPP. Mr. Risan reported that he refers to the Notice to Construct issued by SPP south of Lake Sakakawea as the "Kummer Ridge Project" and the project north of Lake Sakakawea as the "Plaza Project". Basin Electric had requested expedited re-evaluation of SPP's determination that the Roundup to Kummer Ridge Line be built to 115 kV. This re-evaluation had to go through several levels of committees starting with the Transmission

Working Group and the Markets and Operations Policy Committee (**MOPC**). He reported that Tri-State Generation & Transmission Association (**Tri-State**) had offered a motion in the MOPC meeting that the line be approved as recommended by SPP staff (345 kV), which failed by a large margin. A subsequent motion was offered to build the line to 345 kV but to operate it at 115 kV. That also failed.

The project was then forwarded to the SPP board of directors. In the ensuing dialogue at the SPP board meeting, Mr. Risan discussed Basin Electric's phased-in approach in order to mitigate our risk which is a combination of generation and transmission to meet the aggressive Bakken load growth; that this project had been reviewed under the Integrated System and Mid-Continent Area Power Pool processes and that it was not just a gimmick to get a 345 kV line for cost allocation purposes. Several of the SPP board members had attended the MOPC meeting, but had a different perspective than the MOPC. The SPP staff did a very good job of supporting its argument before the board and the board voted to approve the project at 345 kV rather than 115 kV.

Mr. Risan noted that this action leaves the door open for Basin Electric to also possibly apply for regional recovery of the Patent Gate to Roundup 345 kV line in the future.

Staff continues to work on the Plaza Project with Mountrail-Williams Electric Cooperative.

A. Authorization to Accept Expected SPP Notice to Construct the Roundup-Kummer Ridge Transmission Line at 345 kV

Mr. Risan reported that while we don't yet have the final notice to construct from SPP, he wanted to be prepared when it does arrive. He recommended authorization to accept the SPP Notice to Construct the Roundup-Kummer Ridge Transmission Line at 345 kV.

After discussion, it was moved by Director Thiessen, seconded by Director Presser and carried that the following Resolution be adopted:

R07.08-09-16 RESOLVED, that Basin Electric staff is hereby authorized to accept the Southwest Power Pool's Notice to Construct the Roundup to Kummer Ridge section of AVS to Neset Transmission Line at 345 kV; and

BE IT FURTHER RESOLVED, that the CEO & General Manager, or his designee, be authorized to execute the required documents.

Mr. Risan reported that we need to pick up where we left off with the two alternative routes for this project. Seventy percent of the west route right-of-way has been acquired, but the next step would be condemnation. Mr. Greek noted that Mr. Eggl will take another stab at the east line with the Three Affiliated Tribes; however, the Tribes' last offer was to sell the right-of-way across their ranch for $32 million.

Annual Transmission Revenue Requirement filing. Tom Christensen is attending a technical conference today where he and staff will review formula template changes. There is a small chance these issues could be resolved prior to the August 18 settlement conference at FERC. He noted we are close to a settlement with all but Missouri River Energy Services, which is pushing back on the hypothetical equity ratio issue.

Mountain West Transmission Group (**MWTG**). The next biggest frontier is the west. A Request for Information was issued to SPP, Pennsylvania/Jersey /Maryland Interconnection (**PJM**), the California Independent System Operator (**CAISO**) and MISO. A series of meetings have been held. Mr. Risan participated in the first two days of meetings. His reaction was that all parties did a good job presenting their case but the perception from MWTG is that SPP is not a done deal because the SPP costs came in much higher than MISO. Mr. Risan thought that the CAISO would be rejected. There were some CAISO efforts to accommodate a multi-state RTO but this week the governor of California issued a letter to the governors of its neighboring five states informing them that California is not yet ready to expand CAISO beyond its borders. With CAISO dropping out, it is possible the MWTG might attract a few more utilities such as Public Service of New Mexico or possibly PacifiCorp. Likewise, PJM would be the next likely respondent to be eliminated because the tariff region is on the east coast and a satellite office would have to be established. Our biggest concern right now is with Black Hills Power (**Black Hills**) as they appear to be in the MISO camp based on the proposed lower administrative costs. Putting the Rapid City DC Tie into the west-side RTO might offset the higher administrative costs for Black Hills. Mr. Risan noted that he spoke with Bob Harris regarding Western's position. Mr. Harris was cautious because Western must go through a public comment process and must show no bias.

After those three meetings, Mr. Risan wrote a draft position paper to eventually offer to SPP that would address needs. He shared the paper with Tri-State, which responded positively. The paper has not yet been released to the rest of the MWTG because it's not yet ready. Mr. Risan noted that he would like to approach SPP with some recommendations/requests to possibly reduce its proposed administrative costs.

The MWTG decision affects Basin Electric's power supply decisions.

18. Recess and Reconvention

At 12:00 p.m. President Peltier recessed the meeting until 1:00 p.m., at which time the meeting reconvened with President Peltier continuing to preside and Secretary Gary C. Drost continuing to keep the minutes.

19. Roll Call

After calling the roll, the Secretary reported the following Directors present:

Donald E. Applegate	Paul Baker
Leo Brekel	Gary C. Drost
Charles Gilbert	Mike McQuistion
Kermit Pearson	Wayne Peltier
Troy Presser	Roberta Rohrer
Allen Thiessen	

Said persons being all of the Directors of the Cooperative. Also present were Chief Executive Officer & General Manager Paul M. Sukut, Assistant Secretary Mark D. Foss and Basin Electric staff members Lynn Beiswanger, Tracie Bettenhausen, Andy Buntrock, Eric Carufel, Kelly Cozby, Shawn Deisz, Tammy DeWitt, Elizabeth Erhardt, Matt Greek, Deb Haga, John Jacobs, Steve Johnson, Becky Kern, Matt Kolling, Tom Leingang, Sharon Lipetzky, Lisa Maurstad, Tracy McBride, Darla Miller, Deb Olafson, Diane Paul, Curt Pearson, Dave Raatz, Mike Risan, Ken Rutter, Susan Sorensen, Michelle Wiedrich and Mike Zimmerman.

Also present were DGC Vice President David J. Sauer, Upper Missouri manager Claire Vigesaa and Mor-Gran-Sou manager Don Franklund.

20. Human Resources Report

A. Equal Employment Opportunity Commission.

Senior Vice President of Human Resources Diane Paul reported that the Equal Employment Opportunity Commission complaint at LRS had been dismissed. Its findings mirrored those of the state agency that performed the initial investigation. She noted that she has received notice that a former AVS employee has filed a charge of discrimination.

B. Medical Services

Ms. Paul reported that the trial period of providing medical services to dependent family members at headquarters in July was very successful. As a result, this service will be expanded on a trial basis to the other North Dakota facilities. Blue Cross/Blue Shield (**BC/BS**) reports the average cost to visit a medical provider is $227. Currently, there are 3,339 dependents covered at the Cooperative's facilities. The savings could be substantial.

C. Benefits

Director of Labor Relations & Benefits Deb Haga reported on the recommendations made by the benefits broker, Hays Group (**Hays**). The Benefits division has received preliminary numbers from BCBS which is based upon claims filed and is reviewing BC/BS proposed administrative fee. Hays has recommended that we consider marketing the Cooperative's stop-loss coverage and review the contract with Prime Therapeutics (which provides mail order prescriptions). Hays has performed a comprehensive search for alternate vendors for dental insurance, performed a comprehensive review of BC/BS utilization data, performed a short-term disability review, assessed the possibility to save money on the ancillary life insurance, accidental death and dismemberment and long-term disability insurance coverages we purchase from UNUM, as well as searched for alternate vendors for vision insurance.

The goals for 2017 are to look for cost savings and to eliminate commissions, maintain current coverages with no disruption to the employees and conduct a comprehensive review of plans and utilization for development of 2018 recommendations. Final recommendations will be complete by the October Board meeting.

Ms. Haga noted that due to the lateness in the year, the only potential change under consideration for 2017 would be a dental carrier change. Open enrollment is in October. Staff will get more deeply into the data during the first quarter of 2017 for potential revisions in 2018.

D. Safety

Safety/Occupational Health Administrator Kelly Cozby reported that the headquarters "Our Power, My Safety" (**OPMS**) focus card participation reached a new high in July. Items for the OPMS Steering Team August planning meeting include updating the charter and their planning calendar and reviewing the OPMS leadership training program. Upcoming activities include the Rapid Improvement Workshops for the "Train-the-Trainer Class" and for Continuous Improvement Teams #4, #5, and #6, as well as safety perception survey planning.

21. Financial Services Report

Senior Vice President & Chief Financial Officer Steve Johnson reported that CoBank ACB's second quarter financial results show interest income up 12%, average loan volume up 14% and net income up 5%, all compared to the second quarter of 2015.

Mr. Johnson reviewed the austerity measures he had shared with the rating agencies, which total $234.0 million through July 2016. The agencies acknowledged that the Board of Directors, CEO and management were following through with austerity measures. He then discussed in detail each meeting with the rating agencies.

A. Approval of 2017-2026 Financial Forecast

Manager of Financial Planning & Forecasting Andy Buntrock went over the changes from the forecast presented at the July Board of Directors meeting. He reported there were changes to production operations, fuel and production maintenance, primarily at AVS, LRS and DCS. There were administration revisions via changes to maintenance, consulting and software. There were cash revisions via changes to interest expense and interest income. The net changes ranged from ($1.0 million) on the front end to ($4.0 million) on the back end.

He reviewed the Basin Electric margin both before and after tax for each year of the forecast, noting that the average member rate was held constant at 64.2 mills/kWh for the forecast term. He compared the average member rate to Minnkota's rates over the 10-year period (variation in delivery point, Western allocation) from 76.3 in 2017 to about 81 mills/kWh in 2022 and GRE's rates of 76 to about 83 mills/kWh over the same period.

He reviewed the Cooperative's liquidity, expenditures and cash flow. No new long-term debt was included in this forecast. He noted we still expect to issue $325 million of long-term debt yet this fall. Capital expenditures were decreased by half from what was projected in the 2016-2025 financial forecast. The consolidated financial metrics did not change from what was presented last month.

Mr. Buntrock then recommended that the 2017-2026 Financial Forecast be approved.

After discussion, it was moved by Director Pearson, seconded by Director Drost and carried that the following Resolution be adopted, with Directors Applegate and Gilbert voting "no".

R08.08-09-16 RESOLVED, that the Board of Directors hereby adopts the Basin Electric Power Cooperative 2017-2026 Ten-Year Financial Forecast as presented.

B. Approval of 2017 Rate Schedule A

Rate & Load Analyst Elizabeth Erhardt outlined the specific components of the proposed 2017 Rate Schedule A. For 2017, the base and fixed CROD demand and energy rate component levels would be maintained at current rate levels in effect after an intra-year increase approved at the Board of Directors' June meeting and effective August 1. The 2017 contract extension credit rate components will be adjusted to result in a $40.2 million discount for members that have extended their contracts through 2075. The base rate demand period waiver would start up in 2017 with the intent to maintain the waiver for a period of at least five years. The average mill rate cap of member costs would be eliminated.

With respect to special rates, the 2017 electric heat rate would be held constant at the 2016 rate level, as well as the dual fuel heat rate and the interruptible rate would be the base energy rate. Various standby rates would be set in SPP, MISO, NW Energy and CUS/PAC. The same would be the case for the 2017 PURPA rate. Collectively, these rates are designed to generate approximately $1.6 billion in revenues. The average Class A rate for 2017 would be 64.2 mills per kWh and becomes effective January 1, 2017.

With respect to purchase rates, the renewable energy purchase rate would sunset after taking applications through December 31, 2016 (subject to the 10 MW cap). Mr. Raatz noted that the MAC had recommended maintaining this purchase rate and increasing the cap from 10 MW to 12 MW, but eliminating new member projects from the rate.

Starting January 1, 2017, the solar pass-through rate would be renamed to the renewable resource pass-through rate. The rate would allow for Basin Electric to purchase the net generation from solar, wind, hydro or biomass generation projects up to 150 kW in size, from consumer- or member-owned projects at Basin Electric's avoided cost. Such net purchases would be considered a Basin Electric point of delivery to the member per the wholesale power contract. The 2017 renewable pass-through rate would have a 7 MW cap. There would be no change in the environmental attributes purchase rate and the load data incentive rate.

After discussion, it was moved by Director Gilbert to approve the 2017 Rate Schedule A with the exception of including the MAC recommendation with respect to the Renewable Energy Purchase Rate. The motion died for lack of a second.

After discussion, it was moved by Director McQuistion, seconded by Director Drost and carried that the following Resolution be adopted, with Director Gilbert voting "no":

R09.08-09-16 RESOLVED, that the Board of Directors approves the 2017 Rate Schedule A as presented to this meeting including, but not limited to:

(a) The Base Rates, the Fixed CROD Rates, the Contract Extension Credits, the Base Rate Demand Period Waiver and elimination of the average mill rate cap;

(b) Special Purchase Rates including the electric heat rate, dual heat rate, interruptible rate, standby rate and PURPA rate;

(c) The Purchase Rates including the load management rate, c-bed methane rate and the solar pass-through rate which will be renamed "Renewable Resource Pass-Through Rate" and include solar, wind, hydro and biomass purchases; and

(d) Elimination of the Renewable Energy Purchase Rate on December 31, 2016.

BE IT FURTHER RESOLVED, that the staff is directed, in the preparation of the proposed 2018 rates, to review the level of the electric heat rate.

C. Accounting Report

Senior Accounting Analyst Darla Miller reported that the July 2016 Statement of Operations reflected an estimated net margin of $23.6 million compared to the budgeted net margin of $18.6 million for a favorable variance of $5 million. The net margin last month was $19.8 million and the margin for July 2015 was $12.8 million.

July member sales were $122.5 million compared to the budget of $129.3 million for an unfavorable variance of ($6.8 million). Year-to-date sales are approximately $44 million below budget.

June sales to members were $114.1 million compared to sales to members of $108.4 million in July 2015.

July surplus sales were $14.6 million compared to the budget of $17.9 million for an unfavorable variance of ($3.3 million). June surplus sales were $17.6 million and for July 2015 surplus sales were $27.2 million.

There was $1.9 million in other revenue due to a settlement payment received relating to an annexation by the city of Gillette, Wyoming.

Mr. Rutter then reported that July SPP/Montana highlights included a net $5.4 million favorable variance from budget. The average transacted load zone purchases were $28.78 versus a budgeted price of $28.08. The average transacted surplus sales price was $13.60 versus the budgeted price of $26.75. Loads were down but somewhat offset by unaccounted for energy loads.

SPP member energy loads for the month were under budget by approximately 100 MW; however, unaccounted for energy loads somewhat offset this impact.

July presented fairly normal congestion patterns for most of the month, however, the McHenry transformer constraint at month-end caused additional PGS dispatches.

The 25 MW July Mid C Swap at $28.55 settled favorably against the market at $31.53 and was used to hedge Montana load.

Mr. Rutter reported that July MISO highlights included $1.0 million favorable variance from budget. The average transacted load zone purchases were lower than budget $23.17 versus a budgeted price of $28.58. The average transacted surplus sales price was $24.16 versus a budgeted price of $24.49.

West July highlights included a ($0.5 million) unfavorable variance from budget. The average transacted day-ahead and real-time sales price was approximately $28.12 versus the budget of $28.36.

The west units were online all month although DFS was slightly derated as a result of high ambient temperatures. Power was primarily moved from west to east across the ties throughout the month.

The Mount Elbert pumped storage optionality was utilized for super-peak hours.

Even in the heat of summer, it continues to be difficult to sell off-peak energy. West-side wind in the off-peak is dramatically impacting prices.

Ms. Miller then reviewed operations expenses, maintenance expenses, year-to-date consolidated net income/loss, changes to the balance sheet and month-end cash.

Basin Electric's July equity-to-asset ratio was 17.3% compared to 17.2% in June.

The July equity-to-capitalization ratio using the Moody's methodology (both without the consolidation entry for The Coteau Properties Company) was 20.8% compared to 20.7% in June.

The July equity-to-capitalization ratio based on indenture requirements for patronage distribution was 20.1% compared to 19.7% in June.

22. Directors' Reports

Director Thiessen reported on Upper Missouri's summer board meeting in Medora.

Director Gilbert reported on his tour of several Basin Electric's facilities in McKenzie Electric Cooperative's area and noted that the substations are massive.

23. Recess and Reconvention

At 3:30 p.m. President Peltier recessed the meeting until August 11, 2016 at 8:00 a.m. at which time the meeting reconvened with President Peltier continuing to preside and Secretary Gary C. Drost continuing to keep the minutes.

24. Roll Call

After calling the roll, the Secretary reported the following Directors present:

Donald E. Applegate	Paul Baker
Leo Brekel	Gary C. Drost
Charles Gilbert	Mike McQuistion
Kermit Pearson	Wayne Peltier
Troy Presser	Roberta Rohrer
Allen Thiessen	

Said persons being all of the Directors of the Cooperative. Also present were Chief Executive Officer & General Manager Paul M. Sukut, Assistant Secretary Mark D. Foss and Basin Electric staff members Tracie Bettenhausen, Eric Carufel, Shawn Deisz, Ken Dolan, Elizabeth Erhardt, Matt Greek, John Jacobs, Steve Johnson, Becky Kern, Sharon Lipetzky, Dave Raatz, Mike Risan, Ken Rutter, Susan Sorensen and Michelle Wiedrich. Also present was Powder River Energy Corporation (**PRECorp**) manager Mike Easley.

25. New Montana Members Activities

Mr. Raatz discussed the proposal details and economics of the formation of a Class A G&T by PRECorp which PRECorp, Fergus and Tongue River would join as distribution members, and of Mid-Yellowstone joining Upper Missouri. Based on today's discussion, PRECorp will request Basin Electric's approval to proceed with this concept in September.

Basin Electric's existing contracts with Upper Missouri and PRECorp call for the new Montana members to join on October 1, 2017; the new proposed contract would move this date to January 1, 2017.

Mr. Raatz reported that Southern Montana Electric G&T (which is in the process of winding down its corporate existence) is the current power supplier for the three aforementioned Montana cooperatives and supplies these cooperatives through a purchase from Twin Eagle.

Tongue River is contiguous to PRECorp but Fergus is not. So Basin Electric will determine Fergus' demand billing on a noncoincident basis. Those types of arrangements will not change for the January through September time period.

Basin Electric's power supply for this January through September period would include the $34.4/MWh Southern Montana purchase from Twin Eagle, so the Fergus three-mill parity adder (for 15 years) would still not start until October 1, 2017.

Because Basin Electric is taking assignment of the Twin Eagle contract and then will be charging a higher price, staff has determined that it is appropriate to give those cooperatives the benefit of the Twin Eagle purchase. In addition, the Montana cooperatives will avoid Northwestern Energy wheeling and any energy imbalance risk.

The net power and wheeling cost to these three Montana members will be $2.3 MWh higher on average $620,000.

He presented a chart showing Montana member economics with today's charges, January through September charges and October 2017 forward charges.

Mr. Raatz then reviewed the amendments, assignments, terminations and execution of contracts required.

Mr. Foss reviewed the timeline for the membership application process and bylaw amendments, as well as the contracts to be assigned. Basin Electric has already received Mid-Yellowstone's application for Class C membership.

PRECorp manager Mike Easley expressed his gratitude to the Basin Electric employees who worked on this project. Basin Electric has been extremely helpful and PRECorp is committed to its relationship with Basin Electric.

Mr. Easley reviewed PRECorp's Mission and Vision Statement and noted that PRECorp, Fergus and Tongue River had decided to pursue Dorsey & Whitney's Federated G&T Model after reviewing the alternative contracts and agreements for the Wholesale Power Model. Dave Swanson and a team at Dorsey & Whitney have continued work preparing entity formation documents, requisite board actions and related contract documents. He reviewed the timeline for PRECorp's membership application and bylaw amendments.

He reported that this action is being taken due to growing concerns about PRECorp's ability to maintain its Basin Electric Class A board seat, the opportunity for increased presence and visibility in preparation for the growing movement and interest in a west-side RTO, opportunities for additional members due to the more traditional structure and the "PRECorp centric" nature of the provision of services may be limiting the full potential of PRECorp's cooperative outreach strategy.

At this time, PRECorp will provide management services to the new G&T, but it hopes to create a services cooperative similar to the Innovative Energy Alliance in North Dakota.

The application and contract process is fairly complicated. During their August board meetings, all cooperatives will adopt a set of resolutions that provide the board with the authority to execute the required contracts. PRECorp has already received Fergus' Class C membership applications.

The name of the G&T will be "Members 1st Power Cooperative" (**Members 1st**). Associated Electric Cooperative (**Associated Electric**) has a retail brand called "Members 1st", so PRECorp has requested Associated Electric's consent to use the Members 1st name and is optimistic that consent will be granted.

The new G&T will be formed by the September Basin Electric Board meeting. After that, the activity is on the Basin Electric side and, ultimately, once the membership vote is taken on the bylaw changes and hopefully approved, Members 1st will have second board meeting to approve the contracts and the assignment. Basin Electric approval of these membership applications will be presented to the Basin Electric Board at its December meeting and Members 1st would be ready to receive power on January 1, 2017.

Mr. Easley then discussed franchise discussions and annexation struggles with the city of Gillette and the cities of Upton/Newcastle.

26. Date and Time of Next Board Meeting

The next regularly scheduled meeting of the Board of Directors will take place September 13-15, 2016, at the headquarters building in Bismarck, North Dakota. It was also noted that the Resolutions and Bylaw Review Committees will be meeting during this time as well.

27. Adjournment

President Peltier adjourned the meeting at 8:50 a.m.

Gary C. Drost
Secretary-Treasurer