Approved October 10, 2017

# Basin Electric Power Cooperative
# Bismarck, North Dakota

## Minutes of the Regular Meeting of the Board of Directors
## September 12-14, 2017

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# Bismarck, North Dakota

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## September 12-14, 2017

The regular meeting of the Board of Directors of Basin Electric Power Cooperative (the **Cooperative** or **Basin Electric**) was held at the headquarters building, 1717 East Interstate Avenue, Bismarck, North Dakota, on September 12, 2017 starting at 8:00 a.m. CDT.

1. **Call to Order**

   The meeting was called to order by President Wayne Peltier, who presided, and Assistant Secretary Roberta Rohrer, who kept the minutes thereof.

2. **Roll Call**

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

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

   Said persons being all of the Directors of the Cooperative except Gary C. Drost, who was absent. Also present were CEO and General Manager Paul M. Sukut and Assistant Secretary Mark D. Foss and staff members Chris Baumgartner, Eric Carufel, Lisa Carney, Matt Greek, Steve Johnson, Becky Kern, Diane Paul, Dave Raatz, Mike Risan, Ken Rutter, Valerie Weigel and Michelle Wiedrich. Also present were Corn Belt Power Cooperative (**Corn Belt**) director Scott Stecher, Corn Belt manager Kenneth Kuyper, East River Power Cooperative (**East River**) director Les Mehlhaff, Mor-Gran-Sou Electric Cooperative (**Mor-Gran-Sou**) director Vernard Frederick, Upper Missouri Power Cooperative (**Upper Missouri**) director Travis Thompson, Dakota Gasification Company (**DGC**) directors James Geringer and Alan Klein and DGC Vice President David J. Sauer.

3. **Recess and Reconvention**

   At 8:02 a.m., President Peltier recessed the meeting in order to hold the Board Committee meetings and the Board Audit Committee meeting. The meeting reconvened at 11:25 a.m. with President Peltier continuing to preside and Assistant Secretary Roberta Rohrer continuing to keep the minutes.

4. **Roll Call**

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

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

Said persons being all of the Directors of the Cooperative except Gary C. Drost, who was absent. Also present were Chief Executive Officer and General Manager Paul M. Sukut, Assistant Secretary Mark D. Foss and Basin Electric staff members Chris Baumgartner, Tracie Bettenhausen, Shawn Deisz, Tammy DeWitt, Matthew Greek, John Jacobs, Steve Johnson, Becky Kern, Diane Paul, Dave Raatz, R.D. Reimers, Mike Risan, Ken Rutter, Valerie Weigel and Michelle Wiedrich.

Also present were East River director Les Mehlhaff, Mor-Gran-Sou director Vernard Frederick, Rushmore Electric Power Cooperative (**Rushmore**) manager Vic Simmons, Upper Missouri director Travis Thompson, Upper Missouri manager Claire Vigesaa, DGC Vice President David J. Sauer and a number of members of the 2017 Basin Electric Resolutions Committee.

5. **<u>OneOK</u>**

Director Thiessen reported that a couple weeks ago, ONEOK, Inc. (**ONEOK**) contacted McKenzie Electric Power Cooperative (**McKenzie**) requesting rate relief and access to the market claiming ONEOK could save $70 million a year by going to the market rather than purchasing from Upper Missouri. A few days later, Mountrail-Williams Electric Cooperative received a very similar call. This is a huge load for the distribution cooperatives, Upper Missouri and Basin Electric. ONEOK is approximately 30 percent of Upper Missouri's load. If ONEOK gets this done, a precedent would be set, so we need to do everything we can to retain this customer. A number of options were discussed at Upper Missouri.

He noted that a couple months ago, he brought a resolution from Upper Missouri to the Basin Electric Board recommending Basin Electric hold excess funds in asset retirement or deferred revenue accounts. We may not have time to do this. If there's a positive side to this situation, it's that we got this information prior to the strategic planning session next week. During our last strategic planning session, we discussed signposts for Basin Electric and Director Thiessen stated this is one very clear signpost.

He introduced Travis Thompson, Upper Missouri board chairman and McKenzie director, who entertained questions. When asked about the cost of service, Mr. Thompson reported that ONEOK had come in last year and Upper Missouri walked through its cost of service so ONEOK would understand everything that goes into their cost of service. Upper Missouri runs an extremely slim margin on ONEOK sales. At that time, ONEOK seemed to understand.

Mr. Thompson noted that loss of this load would definitely result in a rate increase. He noted that ONEOK is being pushed by the field operators, who see this as a way for ONEOK to reduce its power cost. It's probably a break-even for ONEOK. If ONEOK is successful, the oil companies are likely waiting in the wings to do the same thing and it will result in a downward spiral. He requested that Basin Electric staff be allowed to participate in McKenzie's upcoming meeting with ONEOK.

Mr. Thompson then introduced McKenzie Chief Operating Officer Gary Hailey. Mr. Hailey noted that McKenzie is 13 percent of Basin Electric's load. ONEOK is 50 percent of McKenzie's load. ONEOK is a mid-stream gas processing company that does business with 14 power distribution cooperatives, many of which are served by Basin Electric. Collectively, ONEOK spends $450 million per year for electricity.

He noted that McKenzie is not requesting special treatment. It has some questions. What would happen to Basin Electric's bond ratings if it lost 200 MW of load? What would the mill rate increase be? Should we look at a load forecast in two scenarios: one with and one without that load? What can we do differently tomorrow that would better enable us to retain these loads? How many places does ONEOK touch the system? How much total load does it represent? Should we be identifying these other large loads at risk? Is there something different we can do in the business model to apply to all the industrial loads maybe considering self-generation? Should we create a distributed generation subsidiary to steal our own load? Should we have a new rate class for self-generators larger than 50 MW? Should there be an option to allow Basin Electric to operate a member-owned generator? He asked Basin Electric to consider unique structures to retain these loads. Are we willing to think outside the box to retain a 200 MW load? It would be easier than finding new load. Would Basin Electric consider an engineering cost-of-service study to truly understand cost of service?

ONEOK spends $120 million per year with McKenzie at a rate of 6.8 to 7 cents. McKenzie adds less than two mills of markup. ONEOK claims it can generate for less than five cents/kW. At that rate, they would save $24 to $30 million a year.

McKenzie has analyzed at least nine possible courses of action. McKenzie believes it stays whole in seven of the cases by wheeling the power. In eight of those scenarios, Basin Electric loses the load. What can we implement as a cooperative family that can be applied to all members to prevent the cherry-picking activity happening now? He requested that Basin Electric staff be allowed to work with McKenzie for the best solution, help influence this decision on the front side and participate in the meeting with ONEOK in Tulsa.

Director McQuistion noted that McKenzie said it doesn't lose in eight of the nine scenarios, but Basin Electric has $1.8 million invested. If McKenzie stays whole, does it have the money up front or is that aid to construction? Mr. Hailey reported that McKenzie does have O&M costs to wheel and that its members made a substantial investment, over $300 million, to help McKenzie service those loads.

Director Thiessen asked if ONEOK gave any indication of how much of a rate decrease it would take to make ONEOK abandon its self-generation plans. Mr. Hailey said there were only two data points for that. One was the conversation that if Basin Electric was easier to deal with, it sure would change the game. The other was ONEOK indicated they were seeing 3.5-cent power through some investor-owned utilities in Oklahoma, which could be their office building in Tulsa.

Director Thiessen noted that the loads are supposed to work with the distribution cooperative and not the power supplier; however, ONEOK would rather work directly with the power supplier. Basin Electric doesn't typically talk to the end consumer. Mr. Sukut said that historically, Basin Electric makes electrons and sells them to the Class A members. It doesn't distribute and doesn't deal with customers. Would it, if a Class A member requested? Mr. Sukut said he would have to discuss it with the Board.

## 6. Recess and Reconvention

President Peltier recessed the meeting at 12:00 noon. The meeting reconvened at 3:15 p.m. with President Peltier continuing to preside and Assistant Secretary Rohrer continuing to keep the minutes.

## 7. Roll Call

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

| | |
|---|---|
| Donald E. Applegate | Paul Baker |
| Charles Gilbert | Mike McQuistion |
| Kermit Pearson | Wayne Peltier |
| Troy Presser | Roberta Rohrer |
| Allen Thiessen | |

Said persons being all of the Directors of the Cooperative except Gary C. Drost, who was absent and Leo Brekel, who was representing the Board of Directors at the 2017 Resolutions Committee meeting. Also present were Chief Executive Officer and General Manager Paul M. Sukut, Assistant Secretary Mark D. Foss and Basin Electric staff members Chris Baumgartner, Tracie Bettenhausen, Dean Bray, Shawn Deisz, Tammy DeWitt, Matt Greek, John Jacobs, Steve Johnson, Sally Meyer, Diane Paul, Mike Risan, Ken Rutter, Kevin Tschosik, Shelly Wanek and Michelle Wiedrich. Also present were DGC Directors James Geringer and Alan Klein, East River director Les Mehlhaff and DGC Vice President David J. Sauer.

## 8. 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, there was a motion that was seconded and carried that the agenda be approved as presented.

## 9. Approval of the Minutes

The minutes of the August 14-16, 2017 Regular Meeting of the Board of Directors were presented and after an opportunity for corrections, there was a motion that was seconded and carried that the minutes be approved as presented.

## 10. General Manager's Report

It was noted that the Board had no problems with allowing Basin Electric staff to work with McKenzie and participate in a meeting with ONEOK in Tulsa.

### A. Western Fuels Association Report

Fuel and Transportation Supervisor Joseph Leingang reported that the August 24, 2017 Western Fuels Association (**WFA**) board meeting was consequential, not so much in terms of dollars, but in terms of principle and achieving a more equitable share of influence on behalf of Basin Electric's members and the Missouri Basin Power Project (**MBPP**) as the composition of WFA member sales evolves.

The two most substantive issues resolved were the WFA management fee structure and the distribution of board seats. Effective January 1, 2018, WFA will release Tri-State Generation & Transmission Association, Inc. (**Tri-State**) Craig Unit #3 from Tri-State's all-requirements commitment and Tri-State's number of board seats will be reduced from four to two. At a special membership meeting, the WFA board will recommend to the WFA membership that its bylaws be amended to increase Basin Electric's board seats from two to four. Lastly, the Restatement of Coal Purchase Contract between WFA and Basin Electric dated March 31, 2011 for the Dry Fork Station (**DFS**) (paragraph 7) will be amended to provide that Basin Electric shall pay a management fee for all tons delivered to the DFS equal to 60% of the management fee payable by the other WFA Class A members. This change shall take effect on January 1, 2018. The WFA fuel policy shall be changed accordingly.

Mr. Leingang then reviewed the resulting change to the WFA management fee as components of Laramie River Station (**LRS**) and DFS coal costs.

The WFA board meeting schedule was also changed from six on-site meetings annually to four on-site meetings (in April, August, October and December) and two WebEx conference call meetings per year.

LRS coal costs are falling due to the decreasing cost of Powder River Basin (**PRB**) coal.

The new Sunflower director, Wes Campbell, was seated. He replaced Charles M. Ayers. Long-time WFA director from Tri-State, Tony Casados, has retired.

The total patronage allocation for 2016 was $621,879. Of this amount, $372,300 is for LRS and DFS. A number of board policy changes were made to coincide with the new board meeting schedule.

## 11. <u>Executive Session</u>

At 3:45 p.m., there was a motion that was seconded and carried that the Board retire into executive session to discuss a union contract and administrative salary recommendations.

At 5:45 p.m., there was a motion that was seconded and carried to arise from executive session.

## 12. <u>Approval of IBEW Local #1593 Labor Contract</u>

There was a motion that was seconded and carried to adopt the following Resolution:

**<u>R01.09-12-17</u>** RESOLVED, that the Labor Agreement with the International Brotherhood of Electrical Workers Local #1593 be approved, and subject to the contract vote of the membership ratifying and approving the contract, that the CEO & General Manager, or his designee, be authorized to execute the contract on behalf of the Cooperative.

## 13. <u>Human Resources</u>

There was then a motion that was seconded and carried to adopt the following Resolution:

**<u>R02.09-12-17</u>** RESOLVED, that the salary recommendations for administrative employees presented to this meeting of the Board of Directors are hereby approved; and

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

There was a third motion that was seconded and carried that the following Resolution be adopted, with Director Presser voting "no":

**<u>R03.09-12-17</u>** RESOLVED, that the salary recommendations for the CEO and General Manager presented to this meeting of the Board of Directors are hereby approved.

## 14. Recess and Reconvention

President Peltier recessed the meeting at 5:45 p.m. The meeting reconvened on September 13, 2017 at 8:00 a.m. with President Peltier continuing to preside and Assistant Secretary Rohrer continuing to keep the minutes.

## 15. Roll Call

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

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

Said persons being all of the Directors of the Cooperative except Gary C. Drost, who was absent. Also present were CEO and General Manager Paul M. Sukut, Assistant Secretary Mark D. Foss and Basin Electric staff members Chris Baumgartner, Tracie Bettenhausen, Shawn Deisz, Tammy DeWitt, Matt Greek, John Jacobs, Steve Johnson, Kerry Kaseman, Becky Kern, Tracy McBride, Darla Kay Miller, Diane Paul, Mike Paul, Dave Raatz, Mike Risan, Ken Rutter, Matthew Simon, Susan Sorensen, Matthew Stoltz, Katrina Wald, Michelle Wiedrich and Mike Zimmerman. Also present were Fitch Ratings Inc. (**Fitch**) representatives Dennis Pidherny and Matt Riley, East River director Les Mehlhaff, Mor-Gran-Sou director Vernard Frederick, Innovative Energy Alliance Manager Donald Franklund and DGC Vice President David J. Sauer.

## 16. Financial Services Report

### A. Fitch Ratings Presentation

Dennis Pidherny, Managing Director at Fitch, discussed Basin Electric and the U.S. Public Power Rating Criteria. He reviewed what Fitch had published about Basin Electric and the consumer-owned power sector. The five elements of Fitch's credit analysis are: (1) governance and management strategy; (2) customer profile and service area; (3) assets and operations; (4) cost structure; and (5) financial performance. With respect to governance and management, Fitch looked positively on the 2016 mid-year rate increase as it reflects positively on the Board and management recognizing a serious issue and responding to it promptly. Fitch has noted the massive size of the Basin Electric system and the $2.8 million capital expansion program that is drawing to a close. In that context, Fitch has noted the Cooperative's load growth has allowed Basin Electric to diversify its generation portfolio. Despite the rate increase, Basin Electric's wholesale power rates remain lower than surrounding utilities. He pointed to the large increase in Basin Electric's debt to fund the capital build-out. In response to a question from Director Gilbert, Mr. Pidherny stated that if an equity write-off did not affect cash flow, it would probably not affect the Cooperative's credit rating and that what fixed income investors seek is certainty. In response to a question from Director Pearson, he stated that a deferred revenue program would be viewed as a credit positive if it was funded with cash.

As to the public power sector, Fitch noted that the ratio of electric costs to household income has gone down for the past five years in a row. This has happened in part because consumption has declined. Fitch has also observed that the cost of diesel, coal and natural gas are all lower than they were in 2006. Given these conditions, these have perhaps been the best years to operate a utility in the past 30 years.

Fitch has been surprised by the explosive growth of renewables. They note the huge decline in utility investment as there is no meaningful construction going forward, in large part because reserve margins are at an all-time high. With the projected retirement of a large number of both coal and natural gas generating units, the question becomes when does the supply and demand get back into balance?

## 17. Building Cooperative Connections Report

Tax Analyst III Lori Leier introduced the members of the Building Cooperative Connections group from Capital Electric Cooperative, Inc. (**Capital Electric**) and Basin Electric, unfortunately one member, Jerry Doan, was unavailable to attend.

She commended the headquarters, Antelope Valley Station (**AVS**), and Transmission System Maintenance (**TSM**) staff for their presentations and tours. One highlight was being energized at 345 KV. In a follow-up note from our member, Jerry Doan, he recognized this experience as very positive and eye opening, suggesting that Basin Electric continue to get the message out to other Cooperatives.

## 18. Board Committee Reports

**Operations Committee**. Operations Committee Chair Don Applegate reported that the committee heard a report on the ammonia plant cooling water filter project which was approved by the DGC board. He reported that avoiding only one outage to clean heat exchangers will pay the entire $1.6 million cost. The ammonia plant turnaround outage started on August 25. Ammonia shipments continue. Some pipe surface cracks were discovered, but there was no leaking detected. The Committee heard a report on the Leland Olds Station (**LOS**) operating and capital cost-cutting efforts. A significant item in the operating budget is the declining cost of annual maintenance. In 2016 costs were $3.7 million under budget and in 2017 costs were $2.4 million under budget. Excluding coal costs, operations were $1.4 million under budget in 2016 and $2.4 million under budget in 2017. The 2018 maintenance budget was $4.7 million and has been revised to $2.5 million. There will be a major outage at LOS #1 later this month to do spot repairs versus a total replacement of the primary superheater. Lucas Teigen discussed the amendment to the heat/steam trace and insulation contract.

**Finance Committee**. Finance Committee Chair Leo Brekel reported that the committee met with Deloitte & Touche representatives Adam Krasnoff and Judi Dockendorf and discussed the efforts to merge the PrairieWinds subsidiaries into Basin Electric, audit-related matters, the 2016 tax returns and the presentation that will be made at the meeting with the rating agencies in New York later this month.

**Resource Planning & Marketing Committee**. Planning, Resource & Marketing Committee Chair Charlie Gilbert complimented Mr. Rutter, Mr. Raatz and Ms. Kern for their presentations. The group discussed market exposure, how the daily markets work and the risks under various scenarios if our philosophy were to change to allow a certain percentage of our energy requirements to be purchased in the public market.

It was noted that we need to have two viewpoints of the market: short-term (five years and less) and long-term (over five years). Many wind projects will be coming online and one can assume that this will continue for a few years. What happens ten, 15 and 20 years out? If we have older assets, one by one those projects will be retired and then what happens? This will be discussed more thoroughly at the strategic planning session.

There was a presentation on and preliminary preview of a dashboard, an update on the fertilizer marketing study and a discussion of Southwest Power Pool (**SPP**) ancillary services. The group also reviewed the Rate Subcommittee's standby rate.

## 19. Resource Planning Report

### A. Tri-State Contract Status

Senior Vice President of Resource Planning Dave Raatz reported that the contract with Tri-State is finalized and being routed for execution. It will become effective October 1, 2017. Director Brekel thanked Messrs Raatz and Sukut for their work in getting this contract finalized.

### B. Ongoing PURPA Discussion

Mr. Raatz reported that the Public Utility Regulatory Policy Act (**PURPA**) obligates public utilities to purchase power from small qualifying facilities such as hydro, wind and solar, that are 80 MW or less, unless the qualifying facility is located within a Regional Transmission Organization (**RTO**) such as the Midwest Independent System Operator (**MISO**) or SPP, in which case the purchase obligation is 20 MW (based on the assumption that the qualifying facility has non-discriminatory access to the market). The obligation to buy is at the utility's "avoided cost". The PURPA "one mile" rule requires that separate PURPA Qualifying Facility Projects be more than one mile from a different project.

Basin Electric continues discussions with Prevailing Winds in the contexts of both Basin Electric's Request for Proposal (**RFP**) and under PURPA.

If Basin Electric purchased from Prevailing Winds under the Wind RFP, it would be a single 200 MW project, the one-mile spacing requirement would not be applicable and the benefit would be passed on to Basin Electric through a reduced PPA price. However, it would likely be a $2 million/year higher power purchase cost than other RFP options.

### C. Wind RFP/PURPA

Mr. Raatz reported that on August 24, letters were sent to the 10 entities whose wind proposals made the shortlist to inform them that further negotiations and decisions had been postponed until after Basin Electric's strategic planning session and to request confirmation of a proposal pricing extension through December 31, 2017. He then reviewed the shortlisted wind proposals. Only one entity has not extended its proposal through December 2017 as of the board meeting.

### D. Standby Rate

Mr. Raatz reported on the September 8 discussion with the Rate Subcommittee. Feedback was that (1) the standby rate needs to cover Basin Electric's costs of supplying standby service; (2) acknowledgement that the member's standby rate needs to cover Basin Electric's cost plus the member's cost of supplying standby service; (3) agreement that the cost to supply standby service should recognize diversity of when the standby service is provided (high-load-factor resources should receive a higher diversity benefit (lower cost) than low-load-factor resources); and

(4) the energy cost should be the greater of the base rate or the on-peak market index price for the day.

He reviewed the standby rate review timeline, which shows another Rate Subcommittee meeting at the end of September, review with the Board and Managers Advisory Committee (**MAC**) in October and potential action at the November Board meeting.

We are currently considering having three standby rate categories: below 40 percent capacity factor resources; 40 to 70 percent capacity factor resources and over 70 percent capacity factor resources. If small projects don't run at the time of the member's peak, they'd pay the full Basin Electric demand charge. Some say there should be a premium.

There is concern that Basin Electric's Wholesale Power rate is at such a level that large loads will not locate on cooperative lines or will move towards self-generation.

We've done studies on this and will bring information to board in October. Messrs. Raatz and Rutter will also attend an ONEOK meeting, with Upper Missouri and its member, for the Cooperative.

## 20. Transmission Report

Senior Vice President -- Transmission Mike Risan reported that the Transmission System Maintenance staff has worked 340 days without a Days Away, Restricted or Transferred (**DART**) incident. There was one damage incident last month. He presented a photograph and reported that a fire burned through the right-of-way on the Dry Fork to Tongue River-to-Sheridan 230-kV line, burning two complete H-frame structures and one pole of a three-pole structure. The line went out of service on September 2 and was back in service following repairs on September 8.

### A. Status of Contracts with McKenzie

Mr. Risan reported that progress is being made on the five cost-sharing agreements for facilities constructed by Basin Electric and McKenzie to serve new load in its service territory and to interconnect the Lonesome Creek units.

The Kummer Ridge Substation and Patent Gate 345/115-kV Substation cost-sharing agreements are complete and payment has been received.

The Patent Gate 115-kV Switching Station agreement, the Patent Gate-to-Lonesome Creek 115-kV line and the Lonesome Creek generation interconnection agreements are nearing completion.

### B. Mountain West Transmission Group/Southwest Power Pool Negotiations

Mr. Risan reported that negotiation topics continue to be: west-side AC and DC tie cost allocation, administration and exit fees, the West Regional State Committee, reliability coordination strategy, reservation of Transmission Owner Rights and cost-shift mitigation. An example of cost-shift mitigation is where Tri-State has been running into issues with the Western Area Power Administration (**Western**). Western took a hardline position forcing Tri-State into its own rate zone. We supported Tri-State to the extent we could. Basin Electric's relationship with Tri-State is good and Tri-State accommodated us by accepting the MBPP facilities into Tri-State's new rate zone.

The general consensus is we will have a decision to proceed by the September 13-14 meeting in Rapid City, will have an informational meeting with FERC on September 28, hold meetings with the affected west-side public utility commissions by October 13, and host public stakeholder meetings in Denver on October 13 and in Little Rock on October 16. The official public stakeholder and regulatory approval processes will begin shortly thereafter. The most realistic "go live" date is likely not sooner than October of 2019. The probability of the Mountain West group reaching consensus is now estimated at greater than 90%. We can't invite others to join at this time because it could affect the negotiated package deal with SPP. However, once it is up and running, we will probably get several requests for new members, which will lower the costs for all members.

### C. NERC/FERC

Mr. Risan reported that the SPP Regional Entity has elected to dissolve and the North American Electric Reliability Corporation (**NERC**) is in the process of polling the affected utilities as to which region they'd like to have compliance activities administered by. Basin Electric is registered in the Midwest Reliability Organization (**MRO**) and prefers that others do as well. A positive recent development is that Xcel Energy has requested the MRO. NERC has yet to weigh in, so it is not yet final.

## 21. Office of General Counsel Report

Senior Vice President and General Counsel Mark D. Foss reported on litigation and other legal matters of interest to the Cooperative

### A. Board Committee Charters/Board Policies/Bylaw Amendment

Mr. Foss reported that with the charters of the three Board Committees finalized, he began the work to place them in a proposed Board Policy #11 for Board approval. In reviewing the Bylaws to determine if there were any overlooked issues that needed to be addressed, he noted that we do not have existing authority under the Bylaws for the Board Audit Committee.

The proposed amendment to Article VII, Executive Committee, of the Bylaws would provide for the establishment of both an Audit Committee and one or more advisory committees. The Audit Committee would be made up of a minimum of five members of the Board, including the Secretary, and would have the authority to hire and fire the Cooperative's certified public accounting firm, review and accept that firm's audit and approve any other services performed by that firm.

The advisory committees would consist of a minimum of three members of the Board, would have no authority to make decisions on behalf of the Cooperative and would be restricted to making recommendations to the full Board of Directors.

The proposed Bylaw amendment is as follows:

**ARTICLE VII**
**~~Executive Committee~~**
**Board Committees**

**Section 1. Appointment of Executive Committee.** The Board of Directors shall have the power, by resolution, to appoint an Executive Committee consisting of four (4) members of the Board, two (2) of whom shall be the President and Secretary.

The Executive Committee shall hold office at the pleasure of the Board of Directors and shall exercise such powers of the Board as the Board may by resolution delegate to it; and it may be given responsibility for the general direction and management of the Cooperative when the Board of Directors is not in session.

**Section 2. Executive Committee Meetings.** The Executive Committee shall make rules for the calling of its meetings and the conduct of its business. Three (3) members of the Executive Committee shall constitute a quorum for the transaction of its business. Record of all business transacted at meetings of the Executive Committee shall be kept by the Secretary and preserved with the minutes of the meetings of the Board of Directors and the Members.

**Section 3. Audit Committee.** The Board of Directors shall have the power, by resolution, to appoint an Audit Committee consisting of a minimum of five (5) members of the Board to such a committee, one of whom shall be the Secretary. The Audit Committee shall: (1) recommend to the Board of Directors the retention and when appropriate, the termination of the independent certified public accounting firm to serve as the Cooperative's outside auditing firm, (2) negotiate and approve compensation of the auditor on behalf of the Board of Directors, (3) confer with the auditor to the satisfaction of the Audit Committee that the financial affairs of the Cooperative are in order, (4) review and determine whether to accept the audit and (5) approve the performance of any non-audit services provided to the Cooperative by the auditing firm. Record of all business transacted at meetings of the Audit Committee shall be kept by the Secretary and preserved with the minutes of the meetings of the Board of Directors and the Members.

**Section 4. Advisory Committees.** The Board of Directors shall have the power, by resolution, to appoint one or more Advisory Committees, each consisting of a minimum of three (3) members of the Board. Advisory Committees may not exercise the authority of the Board of Directors to make decisions on behalf of the Cooperative, but are restricted to making recommendations to the Board of Directors. Each Advisory Committee shall determine its meeting rules and whether minutes shall be kept.

After discussion, there was a motion that was seconded and carried that the proposed Bylaw amendment be referred to the 2017 Bylaw Review Committee with the recommendation that the committee refer it to the membership for approval at the 2017 annual meeting.

## B. Delegation of Authority Resolution

Mr. Foss reported that the Construction Group had asked whether a certain contract amendment would require Board approval. While his response was negative, Board approval was sought and received and it was agreed that the Board would be consulted about filling a gap in the existing delegation of authority resolution.

The contract in question was for a Board-approved capital project. The original contract was for less than $3.0 million and therefore did not require Board approval. The proposed amendment would take the contract, as amended, over the $3.0 million threshold.

Mr. Foss proposed changes to the delegation of authority resolution clarifying that such an amendment would require Board approval. After discussion, there was a motion that was seconded and carried that the revised delegation of authority resolution be adopted in the form set forth below.

**R04.09-12-17** RESOLVED, that within the policy framework established by the Board of Directors, the CEO and General Manager is responsible for meeting the Cooperative's member electric power requirements at the lowest cost, consistent with sound business practices by effectively planning, organizing, directing and controlling the day-to-day business activities of the Cooperative. To accomplish these activities, the CEO & General Manager is hereby authorized to:

1. Approve all purchase, sale and other contractual arrangements involving the expenditure or commitment of the Cooperative's operating funds;
2. Approve all capital projects in an amount not-to-exceed $1.0 million. If an amendment or change order for a capital project would subsequently cause the capital project to exceed $1.0 million, Board of Directors' approval shall be required. Capital projects in excess of $1.0 million must be submitted to the Board of Directors for approval.
3. Subject to the foregoing, capital projects exceeding the original approved project budget amount in the aggregate by the lesser of 10 percent of the original approved amount or $500,000 must be resubmitted to the original approvers (either the CEO & General Manager or the Board of Directors) for approval;
4. Subject to subsection 2, for all capital projects approved by the Board of Directors, approve and execute all contractual arrangements involving the expenditure or commitment of funds in an amount not-to-exceed $3.0 million with the exception of amendments and change orders, which in the aggregate shall not exceed the greater of $1.0 million or 10 percent of the original approved amount. Contractual arrangements for the expenditure or commitment of funds in excess of $3.0 million for capital projects approved by the Board of Directors must be submitted to the Board of Directors for approval. Approval by the Board of Directors will also be required in the event a contractual arrangement approved by the CEO & General Manager involving the original expenditure or commitment of funds in an amount less than $3.0 million for a capital project approved by the Board of Directors would, because of a proposed amendment or change order, exceed $3.0 million. Each month, the Board of Directors will be provided a report of change orders for all capital project contracts involving the expenditure or commitment of $3.0 million or more;
5. Approve and execute any commodity or financial market derivative contract with an undiscounted notional or total contract value as of the effective date not-to-exceed

$50 million and a term not-to-exceed five years; and

6. Delegate such authority and responsibility to staff members as deemed appropriate to facilitate the duties and obligations delegated herein.

## 22. Caucus to Elect North Dakota Director to NRECA

Mr. Foss reported that the caucus to elect the North Dakota director to the National Rural Electric Cooperative Association (**NRECA**) board of directors is scheduled for October 5, 2017 at the North Dakota Statewide Office in Mandan, North Dakota, and that a delegate and an alternate should be named. After discussion, there was a motion that was seconded and carried that Director Thiessen serve as the delegate and Director Presser as alternate to this caucus.

## 23. Government Relations Report

Senior Legislative Representative Jean Schafer reported on President Trump's visit to the Andeavor (formerly Tesoro) Refinery in Mandan, North Dakota, to discuss his tax reform plan.

DGC wants an expert from the Netherlands to assist with the urea plant startup and training. Through Senator Hoeven's office, staff is working to allow this expert to work in the United States. His visa interview took place on September 7 and was denied pending additional information regarding his contracted work. He later emailed the contract to the State Department and should be cleared shortly.

Basin Electric's internal group on the Clean Power Plan (**CPP**) replacement proposal is working with Tri-State on some ideas and options. A new NRECA Environmental Policy Committee has been established. Environmental and Government Relations staffs are part of this committee which is currently working on CPP replacement and the Migratory Bird Act.

With respect to New Source Review (**NSR**), staff is working with the Carbon Utilization Research Council (**CURC**) on the two existing bills in the House, one on an exclusion for efficiency, pollution reduction and reliability projects and one that changes the measurement of emission increases from annually to hourly. Government Relations is working with Basin Electric's Environmental staff to develop Basin Electric's preferred option for NSR.

Basin Electric is supporting the two Internal Revenue Code Section 45Q bills introduced by Senator Heitkamp and Senator Hoeven. Minor concerns were raised by CURC on the Hoeven bill due to Class 6 sequestration rules (RR) versus Class 2 Enhanced Oil Recovery well rules (UU).

Ms. Schafer then reported on activities of Basin Electric's Political Action Committee.

The findings of the Department of Energy (**DOE**) study on coal-fired generation was released August 24, 2017. The study's findings were: (1) the primary reason coal and nuclear plants are closing is that they are being priced out of the market by cheap natural gas from new shale fields, and (2) the rise of wind and solar, government regulations, and stagnant electricity demand, are secondary causes. The DOE has decided it will not use its emergency powers under the Federal Power Act to take any extraordinary measures to preserve coal-based generation.

Key policy recommendations of the study include accelerating siting and permitting of grid infrastructure, review regulatory burdens for generation and transmission infrastructure projects, fix NSR to allow coal-fired power plants to improve efficiency and reliability, DOE targeting research and development programs to increase efficiency, expediting the processing of liquefied natural gas exports and cross-border natural gas pipeline applications, expediting DOE's efforts with states, RTOs and other stakeholders to improve energy price formation in wholesale electricity markets, focus additional research and development efforts to enhance system reliability and resilience and support electricity workforce development

The NET Power project site located in LaPorte, Texas near Houston survived Hurricane Harvey with very little damage.

## 24. Operations Report

Senior Vice President - Operations John Jacobs reported there was one medical treatment and one DART incident during the month.

August generation was 2,533,758 MWh compared to budgeted generation of 2,523,138 MW which is 0.4 percent above the budget. He reviewed forced-outage rate trends for the last 24 months and provided bus-bar costs for the coal-fired fleet (LOS, AVS, LRS and DFS). Year-to-date generation for the solid-fuel plants is 7.9 percent under budget and for the total fleet is 4.5 percent under budget. Operations had another good month with $63.4 million (11.22 percent) under budget.

August operating statistics were as follows:

| Facility | Availability | Running Plant Capacity Factor (net) | Unit Rating | Comments |
|---|---|---|---|---|
| AVS #1 | 99% | 85.5% | 450 MW | 8/8 scheduled outage to place turbine balance shot. |
| AVS #2 | 97% | 98.9% | 450 MW | 8/1 forced outage for water wall tube leak repair, continued from July. |
| DFS | 100% | 104.60% | 386 MW | |
| LRS #1 | 89% | 91.10% | 570 MW | 8/18 forced outage for secondary air heater pin rack drive assembly issue |
| LRS #2 | 100% | 89.47% | 570 MW | |
| LRS #3 | 100% | 89.77% | 570 MW | |
| LOS #1 | 76% | 94.59% | 221 MW | 8/4 and 8/18 forced outages for tube leaks. 8/23 forced outage for high drum level. |

| | | | | |
|---|---|---|---|---|
| LOS #2 | 90% | 89.42% | 448 MW | 8/19 forced outage for RSH tube leaks. |

Mr. Jacobs presented photographs and discussed the installation of a seal air fan and the installation of the booster fans at the Integrated Test Center. The completion date is expected before the first of the year. XPrize will announce the selected five participants by the end of the year. Mr. Jacobs will share the technologies with the Board this fall.

Mr. Jacobs also showed photographs of the August 21 ongoing solar eclipse at LRS and the traffic to Denver from Wheatland, which increased the travel time from 3 hours to 10 to 12 hours. An estimated half million plus vehicles were traveling on Interstate 25 during that time.

He explained the maintenance required for the extensive LRS dumper repair. The existing dumper has been in service for 30 years and has outlived it serviceability. The new dumper will also provide safer access to motors and a cleaner environment in which to service them.

## A. Distributed Generation Report

Distributed Generation Manager Kevin Tschosik reported that natural gas prices for the distributed generating facilities (Groton Generating Station (**GGS**), Culbertson Combustion Turbine (**CCT**), Wyoming Distributed Generation (**WDG**), Spirit Mound Station (**SMS**), Deer Creek Station (**DCS**), Pioneer Generating Station (**PGS**) and Lonesome Creek Station (**LCS**)) were down slightly from the previous month. August generation at the distributed generation facilities, the combustion turbines (**CT**) and the reciprocating engines (**RE**) was as follows:

| Unit | Run Hours | Cpcty Factor (%) | Avg Gen (MW) | Avail (%) | Unit Rate (MW) | Comments |
|---|---|---|---|---|---|---|
| Culbertson CT | 118.55 | 7.43 | 45.24 | 78 | 97 | Hydraulic oil line failure. |
| LCS CT #1 | 0 | 0 | 0 | 0 | 45 | Leaf seal and combustor repairs. |
| LCS CT #2 | 0 | 0 | 0 | 0 | 45 | |
| LCS CT #3 | 371.43 | 37.83 | 34.10 | 97.35 | 45 | |
| LCS CT #4 | 271.17 | 26.56 | 32.79 | 99.67 | 45 | |
| LCS CT #5 | 246.12 | 24.78 | 33.71 | 100 | 45 | |
| PGS CT #1 | 166.5 | 15.60 | 31.37 | 88.43 | 45 | Lube oil pump coupling failure. |
| PGS CT #2 | 173.63 | 15.42 | 29.73 | 98.93 | 45 | |
| PGS CT #3 | 305.05 | 33.36 | 36.61 | 97.48 | 45 | |
| PGC RE #11 | 281.62 | 18.86 | 4.63 | 98.58 | 9.3 | |

| | | | | | | |
|---|---|---|---|---|---|---|
| PGC RE #12 | 279.77 | 20.90 | 5.17 | 99.16 | 9.3 | |
| PGC RE #13 | 243.8 | 18.38 | 5.22 | 85.02 | 9.3 | |
| PGC RE #14 | 180.95 | 18.17 | 6.95 | 99.22 | 9.3 | |
| PGC RE #15 | 0 | 0 | 0 | 0 | 9.3 | Failed cam shaft bearings. |
| PGC RE #16 | 179.33 | 17.89 | 6.90 | 98.95 | 9.3 | |
| PGC RE #17 | 292.83 | 21.98 | 5.19 | 99.49 | 9.3 | |
| PGC RE #18 | 295.27 | 22.34 | 5.24 | 99.87 | 9.3 | |
| PGC RE #19 | 295.12 | 22.26 | 5.22 | 99.89 | 9.3 | |
| PGC RE #20 | 285.53 | 21.01 | 5.09 | 99.38 | 9.3 | |
| PGC RE #21 | 289.33 | 21.35 | 5.10 | 99.89 | 9.3 | |
| PGC RE #22 | 289.07 | 21.26 | 5.09 | 99.87 | 9.3 | |
| DCS | 329 | 28.57 | 193.81 | 72.94 | 300 | Failed generator surge capacitor. |
| Groton #1 | 71.88 | 3.13 | 30.80 | 70.17 | 95 | Completion of SB-192, SB-193, SB-176, HPC 3-5 blade replacement. |
| Groton #2 | 187.78 | 11.00 | 41.40 | 99.95 | 95 | |
| SMS #1 | 0 | 0 | 0 | 0 | 120 | Did not run. |
| SMS #2 | 0 | 0 | 0 | 0 | 120 | Did not run. |
| WDG | | | | 43 | 54 | |

Mr. Tschosik presented photographs and discussed the DCS generator surge capacitor failure and installment of the replacement.

Synchronous condensing hours for August were zero for LCS and 489.33 for PGC.

The east-side peak for wind occurred on August 31, 2017 at 1600 hours. At that time, wind generation was as follows:

| **Wind Project** | **Load Factor during the Peak** | **Average Capacity Factor** | | **Project Total** |
|---|---|---|---|---|
| | | **Month** | **2017** | |
| Baldwin | 92 MW | 24% | 41% | 99 MW |

| | | | | |
|---|---|---|---|---|
| Brady #1 | 124 MW | 38% | 49% | 150 MW |
| Brady #2 | 121 MW | 38% | 46% | 150 MW |
| Campbell County | 92 MW | 35% | 45% | 98 MW |
| Chamberlain/Pipestone | 0 MW | 5% | 20% | 2.6 MW |
| Day County | 49 MW | 28% | 44% | 99 MW |
| Edgeley | 20 MW | 15% | 28% | 40 MW |
| Highmore | 14 MW | 25% | 34% | 40 MW |
| Iowa | 2 MW | 17% | 34% | 45.1 MW |
| Iowa Lakes | 1 MW | 18% | 37% | 21 MW |
| Lindahl | 118 MW | 29% | 38% | 150 MW |
| Minot Wind (2 Nordex turbines) | 5 MW | 18% | 30% | 7.1 MW |
| PWND (GE turbines) | 112 MW | 25% | 42% | 115.5 MW |
| PWSD | 30 MW | 26% | 43% | 162 MW |
| Sunflower | 94 MW | 32% | 46% | 104 MW |
| Wilton | 99 MW | 22% | 37% | 99 MW |
| Total | 972 MW | 33% | | 800 MW |
| Average | | 30% | 39% | |

With respect to Pioneer #15, Mr. Tschosik reported that all parts have arrived at the facility and Wartsila employees are en route to start machining the cam shaft to make the bearing repairs. We are currently cleaning out the crank case as part of our root-cause analysis to determine the failure. We estimate the unit will return to service in mid-October.

LCS Unit #2 did not run due to lack of transmission.

Mr. Tschosik presented photographs and discussed the DCS surge capacitor failure. These capacitors protect the generator from any type of electrical surges. The unit was taken out of service when it began to leak oil. This is an Alstom generator. GE has bought out Alstom but GE does not have replacement parts. The original capacitors were manufactured by Ducati in Italy, but the Ducati employees were on a month-long summer vacation. We reached out to our other alliance members, and they were able to procure the parts from ABB.

## B. Leland Olds Station Update

LOS Plant Manager Jamey Backus reported the LOS employees have worked 116,111 man-hours since the last DART incident. With the outage coming up this month, the plant will be briefing employees about potential hazards associated with the outage and will emphasize the importance of proactive safety measures.

The year-to-date generation is at 90.8 percent of the budget. Since May 9, LOS Unit #1 has had outages for three wall tube leaks. These leaks were attributed to simple erosion over a number of years. More wall tube leaks are anticipated and will be fully inspected during the six-week major outage. There was also a six-day outage to repair a primary superheater leak.

The outage to deslag and waterwash the Unit #2 boiler went well, was under budget and on schedule. There was also an outage to address the motor control center feeder breaker issue and a reheat leak.

Mr. Backus presented photographs and discussed the large wall leak in Unit #1 and derates due to a high absorber inlet temperature, furnace exit-gas temperature testing and a failed bend pulley.

The Unit #1 major outage is scheduled from September 23 to November 4 and will include high-pressure water wash of the boiler, inspection-based tube repairs, 18 expansion joint replacements, ID booster fan damper drive replacements, air heater basket replacements in the cold end, internal inspection of the generator, overhaul of the traveling screens and overhaul of the 1A circulating water pump.

He also discussed the cost of the three major environmental compliance consumables (limestone ($SO_2$), carbon and oxidizer (Hg) and urea ($NO_x$)) and steps taken to minimize these costs. Year-to-date, 110,000 tons of limestone have been hauled to LOS and urea deliveries are scheduled for three semi loads per week. The cost of urea is $329 per delivered ton out of Minneapolis.

In an attempt to minimize these costs, carbon and oxidizer usage were cut significantly in July. Plans to control injection rates are moving forward. Limestone cannot be reduced due to design and urea is still under review. DGC urea production will help with transportation costs.

He then presented photographs and discussed the bottom ash dewatering project. As of August 31, 2017, the LOS lignite coal inventory was 637,652 tons and the PRB inventory was at 146,824 tons. Unit #1 will not burn any coal during the outage so the inventory will build.

## 25. Recess and Reconvention

At 11:50 a.m., President Peltier recessed the meeting until 1:00 p.m., at which time the meeting reconvened with President Peltier continuing to preside and Assistant Secretary Rohrer keeping the minutes.

## 26. Roll Call

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

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

Said persons being all of the Directors of the Cooperative except Director Drost, who was absent. Also present were CEO and General Manager Paul M. Sukut, Assistant Secretary Mark D. Foss and Basin Electric staff members Chris Baumgartner, Tracie Bettenhausen, Nichole Braunberger, Shawn Deisz, Tammy DeWitt, Dan Gallagher, Matt Greek, Tyler Hammar, John Jacobs, Kerry Kaseman, Becky Kern, Gavin McCollam, Diane Paul, Mike Paul, Jean Schafer, Myron Steckler, Valerie Weigel, Michelle Wiedrich and Tiffany Zablotney. Also present were East River director Les Mehlhaff, Mor-Gran-Sou manager Don Franklund and Mor-Gran-Sou director Vernard Frederick.

## 27. Commodity Risk Management Report

Senior Commodity Risk Analyst Nichole Braunberger reported that for 2017, Basin Electric has a combined strategy for East Purchase Power and Natural Gas Burn. As of September 1, the position was hedged up to 16.1 percent of the Risk Management Steering Committee (**RMSC**)-approved maximum limit at an average natural gas price of $3.64/MMBtu. There were no power hedges currently on the books.

For 2018, Basin Electric's natural gas burn was 69.9 percent hedged at an average price of $3.00; for 2019 was 58.3 percent hedged at an average price of $3.18; for 2020 was 52.22 percent hedged at an average price of $3.20; and for 2021 was 27.7 percent hedged at an average price of $3.22.

The open basis position represents volumes in which the Henry Hub portion has been transacted but the Ventura basis has not. Marketing is required to execute the Ventura basis transaction within four months of the trade's settlement date.

The RMSC maximum approved storage position for the 2017-2018 season is 125,000 MMBtus. Injections to date total 55,693 MMBtus at an average inventory value of $2.14/MMBtu, including fuel-in-kind. The average sales price at the time of injection was $2.14/MMBtu. There have been no withdrawals to date. No financial hedges are in place as Basin Electric storage is used for reliability purposes.

Basin Electric's natural gas is hedged at either Ventura or at Henry Hub with a Ventura basis hedge to get back to a Ventura Price. As of September 1, the Ventura forward curve for 2017 was $2.73, for 2018 was $2.70, for 2019 was $2.57, for 2020 was $2.57 and for 2021 was $2.59.

Applying the Ventura forward curve to the hedges executed, Basin Electric's natural gas physical and financial mark-to-market (**MTM**) position saw a favorable change from last month of $2.2 million due to the uptick in the natural gas forward price and some negative settlements. As of August 31, the unrealized MTM loss was ($8.6 million).

In August, Basin Electric had a net receivable total of $15,306 from its counterparties for financial settlements of natural gas hedges.

Moving to power, Ms. Braunberger reported that the west surplus sales position average on-peak hedge price for 2017 is $26.81/MWh and for 2018 is $25.75/MWh. The average off-peak hedged price for 2017 is $21.85/MWh and for 2018 is $19.50/MWh.

The Cooperative's surplus sales in the west are hedged against the Palo Verde Index. Applying the Palo Verde forward curve to the power hedges executed, Basin Electric's power financial and physical MTM position saw an unfavorable change from last month of $554,000. As of August 31, the unrealized MTM gain was $775,000.

The Cooperative also has two long-term physical contracts with Cargill Power from 2018 through 2025. These contracts have an unrealized MTM loss of ($52.6 million) that is not included in the above gain of $775,000.

In August, Basin Electric had a net payable of $76,456 to its counterparties for financial settlements of power hedges.

The hedge position for diesel was unchanged from last month and remains at an average hedged price of $2.42 per gallon for 2017 and $2.56 per gallon for 2018.

The financial hedges for the Cooperative's diesel are executed against the Energy Information Agency (**EIA**) On-Highway Diesel Index. Diesel prices increased slightly over the past month with the September 1 average price for 2017 at $2.71 per gallon and for 2018 at $2.68 per gallon.

Applying the EIA On-Highway Diesel forward curve to the hedges executed, Basin Electric's diesel financial MTM position saw an unfavorable change from last month of $2,000. As of August 31, the unrealized MTM gain was $176,000.

In August, Basin Electric had a net receivable of $7,258 from its counterparties for financial settlement of diesel hedges.

## 28. Marketing & Asset Management Report

**SPP August Highlights**. Director of Marketing and Financial Analytics Valerie Weigel reported that Basin Electric had a $500,000 favorable variance in SPP in August due to the average sales price of $17.85/MWh versus the budget of $23.29/MWh, the average purchase price of $25.08/MWh versus the budget of $23.29, actual wind output being less than budget (which provided the favorable financial results) and energy loads that were below budget for the month.

**August West Financial Highlights**. The Cooperative experienced a $5.8 million favorable variance in the West due to the average purchase price of $33.77/MWh versus the budget of $29.49/MWh and surplus sales totaling $12.0 million versus the budget of $5.5 million.

**MISO August Highlights**. Basin Electric had a zero variance in the MISO due to an average sales price of $24.24/MWh versus the budget of $27.14 and the average purchase price of $23.92/MWh versus the budget of $27.14/MWh. Challenges to sales were the breaking apart of the Palo Verde Index pricing, transmission bottlenecks and renewables. The overall monthly wind-to-load was 12 percent.

**Ancillary Services**. Ancillary service revenue from January through July of 2017 is $8 million.

**Finding Solutions for Changing and Evolving Markets**. Ms. Weigel reported on her plant visits to discuss locational marginal pricing, plant parameters and offer strategies, outages and derates, profit and losses.

## 29. Engineering and Construction Report

### A. Safety

Senior Vice President-Engineering & Construction Matt Greek reported that contractors working on Engineering & Construction coordinated projects worked 302,484 man-hours in August with 16 near misses, four property damage incidents, 13 first-aid cases, zero recordables and a total case incident rate of zero.

### B. Project Funding Chart

Mr. Matt Greek reported that one Basin Electric contract totaling $2.4 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.

### C. MBPP Telecom System Upgrade

Senior Electrical Engineer Chris Goettle noted that, in response to a question during the Board Operations Committee, the portion of this system utilized by the Cooperative's transmission system will be included in the tariff.

He reported that the purpose of this project is to upgrade and replace the existing MBPP Joint Telecom Project system because reliability is getting to be an issue, no support is available for this system and limited replacement parts are available due to the age of the system. The core (phone, mobile rata, data, and voice communications) loop of the microwave system is shared among MBPP, Tri-State and Western RMR. The existing agreement expires in December of 2020.

The scope of the project is to provide core communications support for LRS and the other MBPP substation and transmission facilities and provide additional data bandwidth and increased reliability. Western and Tri-State are each building their own new systems. Full decommissioning of the existing system is not included.

Mr. Goettle reported that design highlights include: the initial plan in the Long-Range Engineering Plan assumed a price tag of $9.8 million, a hybrid microwave and optical loop-protected system, cuts in half the number of sites required, requires one new microwave site at Preston, Nebraska, including five new microwave buildings and includes disaster recovery for channelized circuits and increased data bandwidth for network and security.

He reviewed the project schedule which calls for engineering from September 2017 to January 2018, procurement from December 2017 through April 2018, installation and construction from February 2018 through January 2019 and circuit cutovers from December 2019 through May of 2019. The estimated project cost is $5.7 million, of which Basin Electric's share is 42.27 percent or $2.4 million. Mr. Goettle recommended approval of the project.

After discussion, there was a motion which was seconded and carried that the following Resolution be adopted:

**R05.09-12-17** BE IT RESOLVED, that the MBPP Telecom System Upgrade Project to support operations of the MBPP Laramie River Station and associated transmission facilities at an estimated cost of $5.7 million ($2.4 million Basin Electric share) be approved; and

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

## 30. Member Services & Administration Report

### A. Headquarters Power Outage

Senior Vice President of Member Services and Administration Chris Baumgartner reported on the July 24 and August 22 headquarters power outages, which caused difficulties for the Operations and Marketing Groups, as well as the National Information Solutions Cooperative (**NISC**) which has received IT hosting services from Basin Electric for approximately 12 years. The July 24 outage was caused by contractor error when some electrical tape got into the circuit. The Uninterruptible Power Supply (**UPS**) system did what it was supposed to and opened and Basin Electric's systems were back up and running in short order. NISC's systems, however, took considerably longer to get back on line.

The second incident occurred on August 22. Information Technology staff was working in the server room when they saw the breaker open. The vendor arrived the next day and multiple groups were involved in discussions to try to identify the cause.

The first outage was on the load side of the UPS system. The second outage was on the supply side. Capital Electric had no anomalies at this time. Staff believes, but cannot be certain, that the problem was internal to our system.

There are some things we can do to make our system "more redundant." The short-term plan is to work with Border States Electric and we've ordered a smaller UPS system that will provide a redundant connection for the NISC servers and the Basin Marketing group.

Due to the critical nature of this for NISC and Marketing, the long-term fix is the installation of a dual UPS system sometime next year. Mr. Sukut noted that whether the risk is great enough to install a redundant system is being assessed and will be brought to the Board in the future.

Director Presser asked about the Cooperative's Security and Response Service's (**SRS**) liability should this happen during a weather event. Mr. Baumgartner noted that the contracts contain a clause for acts of God, but the extent of liability was unknown.

Mr. Franklund noted that distribution members also use SRS' services and this outage was worse than a power outage because Mor-Gran-Sou was dead in the water without phone, radio and its automatic meter reading system. This reaches all the way down to the member at the end of the line because communication was impacted.

Director McQuistion asked whether such a small revenue was worth the liability and if a redundant system would remove the risk.

**B. <u>Strategic Planning Update</u>**

Mr. Baumgartner noted that the strategic planning session is scheduled for September 18-19, 2017 at 8:00 a.m. CDT at Legacy High School in Bismarck. Steve Kettler from National Utilities Cooperative Finance Corporation will facilitate the session. Mr. Baumgartner reviewed the agenda for the meeting. He noted that how the outcome of the session is communicated to the members is important.

**C. <u>Annual Meeting</u>**

Mr. Baumgartner reported that the annual meeting pre-session begins with a new managers meeting and social on November 7. Tours of the new west headquarters addition will be available during the social. The annual meeting will start at 8:00 a.m. on November 8 when President Peltier, Mr. Sukut and Mr. Johnson will give their regular reports. Rather than having traditional reports from the other areas of the Cooperative, there will be two panel discussions. Mike Risan, Ken Rutter and Dave Raatz will be on the "Serving the Needs of the Members" panel which will be led by Vic Simmons. John Jacobs, Matt Greek and Dave Sauer will be on the "Operational Excellence" panel which will be led by Don Franklund.

Environmental Protection Agency Administrator Scott Pruitt has been invited to speak at the meeting, but it is likely we will not hear from him until shortly before the meeting. SPP CEO Nick Brown has accepted our invitation to give the keynote speech with the understanding that Administrator Pruitt may or may not be speaking.

The banquet will be the evening of November 8 at the Bismarck Event Center.

SRS will host its traditional breakfast for its members the morning of the November 9 and there will be display booths in the meeting area. Post-conference sessions could be held at this time, but he noted that this time could instead be used for a members-only meeting to discuss the history of DGC and its synergies with the Freedom Mine, AVS and Basin Electric. Feedback has shown there is a great deal of miscommunication about Basin Electric's relationship with DGC and about DGC itself.

The Directors liked this idea and it was suggested that staff could discuss how all the subsidiaries fit into Basin Electric. It was also noted that the one comment they hear again and again is that Basin Electric needs to be transparent. The members want to know what we're doing, where we're headed and how we plan to get there. It was also suggested that we provide the history on fluctuating commodity prices because that will explain the current situation and that DGC has been in this situation before. We should remind them of the past bill credits they received due to DGC. The intent is that when the members leave after the annual meeting, they will have a better understanding of how we got to this point and how we plan to proceed.

Mr. Sukut reported that he received positive comments from the Class A managers on his Friday update call.

Mr. Baumgartner noted that the Board had recommended Bob Harris from Western for the Cornerstone Award. Recommendations for the Cooperative Spirit Award will be taken at the October Board meeting.

## 31. Financial Services Report, continued

### A Accounting Report

Accounting Administrator Darla Kay Miller reported that the August 2017 Statement of Operations reflects a net margin of $35.2 million compared to the budgeted net margin of $33.9 million for a favorable variance of approximately $1.3 million. The net margin in August 2016 was $32.2 million.

Estimated member revenue for August is $133.3 million. Member sales were approximately $11.3 million lower than budget, which includes the July actualization of $2.0 million. August sales are estimated to be $13.3 million less than originally forecasted. A negative volume variance of ($11.9 million) and a negative price variance of ($1.4 million) is estimated.

Estimated surplus sales revenue for August is $23.7 million compared to the budget of $16.8 million. Surplus sales were approximately $6.9 million higher than budget. The $6.9 million above budget includes the July actualization of $0.2 million. August sales are estimated to be $6.7 million more than originally forecasted. A positive volume variance of $6.2 million and a positive price variance of $0.5 million is estimated.

Operating costs were approximately $3.4 million less than budgeted. Operation supervision and engineering were less than budgeted by $0.7 million. Wheeling expenses were less than budgeted by $1.5 million. System control and load dispatching expenses were less than budget by $0.6 million. Purchase power expenses were less than budget by $0.6 million as well. Offsetting these positive variances, administration and general expenses were $1.1 million more than anticipated. In addition, fuel expenses were $0.2 million more than anticipated.

Maintenance expenses were in line with the budget in August. Year-to-date through August 2017, maintenance expenses are approximately $11.1 million less than anticipated.

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

Basin Electric's August Equity-to-Asset ratio was 19.9 percent, the same as in July. The August Equity-to-Capitalization ratio using the Moody's Investor Service's methodology (both without the consolidation entry for The Coteau Properties Company) was 23.4 percent compared to 22.9 percent in July. The August Equity-to-Capitalization ratio based on indenture requirements for patronage distribution was 22.8 percent compared to 22.4 percent in July.

## 32. Directors' Reports

Director Pearson thanked Messrs. Sukut and Rutter for attending East River's annual meeting.

Director Baker reported on the Member 1st Power Cooperative annual meeting, which was attended by Messrs. Sukut, Greek and Baumgartner. Allison McGee is the new board member.

Director Thiessen thanked Mr. Sukut for attending the McKenzie board meeting to help answer questions.

Director Gilbert reported that Corn Belt meets with its partners and members annually in August. He expressed his gratitude to Messrs. Sukut and Baumgartner for participating. Mr. Baumgartner presented an NISC update. Another topic of discussion was the Duane Arnold nuclear station, of which Corn Belt owns ten percent, Central Iowa Power Cooperative owns 20 percent and NextEra owns 30 percent. When Corn Belt and the others purchased this station from Alliant, the license term was through 2025. The license has since been extended through 2034. Alliant has announced plans to construct another large wind farm and during hearings at the Iowa Utilities Board, it was mentioned that that the license for the Duane Arnold facility would not be extended past 2025. Every year up until now, the Iowa Utility Board has stated that this license would be extended. As a result, Corn Belt has intervened. He asked what would happen to this facility if there is no buyer for its power. Other states have closed nuclear plants. Some owners are requesting support from their regulatory agencies.

The Duane Arnold facility has asked its owners to invite their legislators to tour the facility in the hope of gaining support for extending its license. He noted that the Basin Electric directors toured this facility shortly after Corn Belt became a Basin Electric member, but that between then and now, tours were not encouraged and it was difficult to receive authorization to tour a nuclear facility. He noted that should the directors wish to tour the facility, this would be a good time.

Director Brekel expressed his appreciation to Chris VandeVenter for attending the Mid-West Electric Consumers Association (**MECA**) meeting.

Director Applegate reported that Donna Olson had been elected to the Nishnabotna Valley Rural Electric Cooperative board of directors. He also reported that the Northwest Iowa Power Cooperative (Basin Electric District #4) had caucused and nominated Tom Wagner to the Basin Electric Board of Directors. Mr. Wagner is the son of former Basin Electric Director Bill Wagner.

## 33. Additional Western Fuels Association Board Seats

Mr. Sukut noted that Basin Electric will be given two additional board seats at WFA and that people will need to be named to these positions. Director Baker noted that the WFA bylaws must be amended if non-directors are selected for these two seats. After discussion, it was decided that Dean Bray and Joe Leingang would continue to serve as alternates for the four Basin Electric directors on the WFA board. After further discussion, there was a motion that was seconded and carried that Directors Presser and McQuistion be named to the WFA board of directors.

## 34. Basin Electric Board Reorganizational Meeting

President Peltier suggested and it was agreed that the Basin Electric reorganization meeting and the subsidiary annual and reorganization meetings be held at the conclusion of the Basin Electric annual meeting rather than in December when the Board is in a rush to attend the MECA annual meeting.

## 35. Date and Time of Next Board Meeting

President Peltier noted that the next regularly scheduled meeting of the Board of Directors will begin on October 10, 2017 starting at approximately 1:00 p.m. CDT.

## 36. Adjournment

President Peltier adjourned the meeting at 2:45 p.m.

Roberta Rohrer

Roberta Rohrer
Assistant Secretary