Approved January 9, 2017

Basin Electric Power Cooperative
Bismarck, North Dakota

Minutes of the Regular Meeting of the Board of Directors
December 14-15, 2016

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Basin Electric Power Cooperative
Bismarck, North Dakota

Minutes of the Regular Meeting of the Board of Directors
December 14-15, 2016

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, beginning on December 14, 2016 at 3:30 p.m. CST.

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	Kermit Pearson
Wayne Peltier	Troy Presser
Roberta Rohrer	Allen Thiessen
Mike McQuistion	

   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 Andrea Blowers, Eric Carufel, Tammy DeWitt, Mike Eggl, Dan Gallagher, Matt Greek, John Jacobs, Steve Johnson, Kerry Kaseman, Becky Kern, Brian Larson, Mike Paul, Curt Peterson, Colleen Peterson, Dave Raatz, Mike Risan, Dave Rudolph, Ken Rutter, Susan Sorensen, Steve Tomac, Kevin Tschosik and Michelle Wiedrich. Also present were Dakota Gasification Company (**DGC**) Vice President David J. Sauer, East River Electric Power Cooperative (**East River**) director Alan Vedvei and Mountrail-Williams Electric Cooperative (**Mountrail-Williams**) director Blaine Jorgenson.

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 McQuistion seconded by Director Baker and carried that the agenda be approved as presented.

4. **Approval of the Minutes**

   The minutes of the November 7-8, 2016 Regular Meeting of the Board of Directors were presented and after an opportunity for corrections, it was moved by Director Rohrer, seconded by Director Gilbert and carried that the minutes be approved as presented.

5. General Manager's Report

General Manager Sukut reported on the CoBank, ACB (**CoBank**) conference he recently attended.

6. Western Fuels Update

General Manager Sukut reported that the Western Fuels Association board of directors approved the 2017 budget.

7. Transmission Report

Senior Vice President of Transmission Mike Risan reported that the Transmission System Maintenance Division experienced a Days Away, Restricted or Transferred (**DART**) incident on November 1, 2016, when an employee lost his balance and fell off a 2.5-foot high switching platform while manually operating a disconnect switch.

Williston Load Pocket. Mr. Risan reported the Williston Load Pocket peaked on December 7 at 972 MW. The peak in this area last year was 960 MW. He questioned as to whether the pocket will hit 1,000 MW yet this winter. He also pointed out the area within the Williston Load Pocket north of Lake Sakakawea that will probably be the next area to require transmission reinforcement.

SPP Rate of Return Settlement Process. On November 16, 2016, an administrative law judge certified the uncontested settlement of Basin Electric's Annual Transmission Revenue Requirement case. The Commission issued the order on November 29, 2016. The next step will be for the Southwest Power Pool (**SPP**) to make its compliance filing within the next 30 days.

SPP Strategic Planning Committee. Mr. Risan reported that he serves on this committee which hopes to address the large amount of wind generation coming into SPP. One option being looked at is whether SPP could somehow ship some of this wind power into another region of the country. Blaine Erhardt was asked to serve on the newly created Export Pricing Task Force subgroup. The SPP board and many SPP members believe SPP is reaching the saturation point with respect to wind generation and would like to find someone else to take and pay for the wind energy, as well as the transmission to take the wind energy out of the SPP system.

In response to a request, Mr. Risan gave a presentation to this committee on Basin Electric's perspective in terms of what we see coming in our footprint and our power planning process regarding renewables. He reviewed with the Committee how Basin Electric joined the Joint Transmission System, had hydro-thermal integration and had a generation portfolio comprised almost exclusively of coal until the early 2000's. Our portfolio now includes wind and gas generation. He explained the Cooperative's three-tiered system within four different resource planning regions and that we try to balance in order to minimize pancaked rates. He also discussed monitoring gas prices, how we're pushing back on the Clean Power Plan (**CPP**) but are involved in the Integrated Test Center technology to attempt to find a technical solution to address the carbon issue. He concluded that Basin Electric's perspective is that coal should still be in the mix, that our members have a substantial investment in those coal generation assets and we'd like to see those assets operate for their remaining useful lives.

SPP staff then presented overview including facts about SPP. SPP contains 746 generating resources, 50,622 MW coincident peak load (July 2016); 19,900 MW low load (October 2015), 15,728 MW of installed wind, 21,535 MW of wind in the queue, peak wind penetration level of 49.17% (on April 24, 2016) and a peak instantaneous wind output of 11,305 MW (on November 17, 2016). They also reviewed wind locations and SPP's wind and solar potential profile, noting the heavy concentration of wind and solar generation in SPP's legacy footprint.

SPP Generator Interconnection Queue. Mr. Risan reported on the requests in generator interconnection queue with a heavy concentration in southern SPP. SPP is struggling as to how to deal with the magnitude of this additional wind generation given that load growth is essentially static.

Mr. Raatz noted that Leidos had been retained and believes there is 10,000 MW of wind generation going forward in SPP at different levels in the interconnection process. As entities get farther along in those studies, they will have to invest funds. These parties requesting interconnection currently have $9 million tied up in nonrefundable deposits. If Basin Electric wants to build a new resource, we would come in at the back of this interconnection queue. The Midcontinent Independent System Operator (**MISO**) is dealing with these same issues.

He noted that it is important to keep SPP informed of the slowing load growth in the Bakken so they can take that into consideration. He did not know if this slower growth would result in SPP withdrawing its Notice to Construct the Roundup-to-Kummer Ridge transmission line.

Mountain West Transmission Group. Mr. Risan reported that the Mountain West Transmission Group (**MWTG**) met on December 1st, 5th and 8th, and is in the process of developing a term sheet. The group is closer to selecting SPP as the regional transmission organization (**RTO**) of choice. A nonbinding letter of understanding is being developed that will focus on negotiations with SPP, but still allow the group to select a different RTO if negotiations are unsuccessful. A press release will be issued sometime after the first of the year. MWTG is being pressured to share information with the public service commissions on the analysis on cost shifts of combining the systems and implementing a license plate pricing regime. MWTG received studies of The Brattle Group, which is attempting to quantify the potential benefits of this market approach. The initial, high-level market analysis shows a savings of approximately $50 million to $70 million per year. Breaking down the components of Basin Electric's share and other moving pieces such as administrative fees and east-side savings, the Cooperative's expected benefit might be $10 million to $15 million per year in very rough and preliminary numbers. The positive study results make a good case for signing the letter of understanding.

Director of Transmission Compliance Dave Rudolph reported on Basin Electric's North American Electric Reliability Corporation (**NERC**) compliance program. One of the big changes we've been working on is a new program to clarify the roles and responsibilities of Basin Electric and our membership. Since 2007, Basin Electric is the only registered entity with NERC and we have been performing some compliance obligations on behalf of the membership. We've found that this can create challenges. We are now in the process of reassigning some responsibilities to reduce risk to all entities. These discussions have been going on for quite some time and we have been working on agreements and exhibits all year. He said he is pleased to announce that we're very close to a final set of those documents and will begin executing by the first quarter of 2017. The goal is to have all of these new agreements in place by March 31, 2017.

On April 1, 2017, cyber and physical standards go into place and it would be very difficult for Basin Electric to manage these standards on behalf of its members. These agreements between Basin Electric and its members will divide the responsibilities between Basin Electric and its members for the transmission-owning function. To begin, we are focusing on the larger members. For members with just one or two pieces of equipment or facilities subject to NERC regulation, we are discussing transferring ownership of the equipment and facilities (and the associated NERC compliance responsibilities) to Basin Electric so that we're not putting an undue burden on these smaller members from a compliance and regulatory aspect.

A. Purchase of Two 115 kV Load Break Switches at Shannon Substation

Mr. Rudolph reported that Lacreek Electric Association (**Lacreek**) built the Shannon Substation in the 1975 time frame and owns the Martin-to-Shannon 115 kV line and Shannon Substation 115 kV load break switches. Basin Electric leases these facilities and recovers the cost in the SPP tariff.

Basin Electric maintains the Martin-to-Shannon line and Shannon Substation load break switches and recovers the cost in the SPP tariff. Basin Electric coordinates with Nebraska Public Power District on reporting of outages on that line.

Lacreek replaced the load break switches in 2016. The net book value of Shannon Substation load break switches is approximately $500,000. The proposal is for Basin Electric to purchase these switches. Basin Electric would recover these costs in the SPP tariff.

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

R01.12-14-16 RESOLVED, that the CEO and General Manager, or his designee, is hereby authorized to enter into a purchase agreement with Lacreek Electric Association for the Shannon Substation load break switches 1069-L and 1075-L and associated grounding switches at an estimated cost of $500,000, subject to satisfactory negotiation of the final contract language; and

BE IT FURTHER RESOLVED, that the CEO and General Manager, or his designee, is hereby authorized to terminate the existing lease for the Shannon load break switches.

B. Purchase of Dickinson Junction Substation 115 kV Bus, Breakers & Switches

Mr. Rudolph reported that the Dickinson Junction Substation is located on Western's 230 kV line between Bismarck/Mandan and Belfield. Basin Electric owns the 230 kV bus along with the 230/115 kV transformer. Under separate action, Board approval for replacement of the existing 230 kV oil breakers is being requested. Roughrider Electric Cooperative purchased the 115 kV main and transfer bus from Upper Missouri Power Cooperative (**Upper Missouri**). Again, the proposal is to have Basin Electric purchase this equipment. The net book value is approximately $1.2 million. Basin Electric would recover the cost in the SPP tariff.

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

R02.12-14-16 RESOLVED, that the CEO and General Manager, or his designee, is hereby authorized to enter into a purchase agreement with Roughrider Electric Cooperative for the Dickinson Junction 115 kV main and transfer bus with associated breakers and switches at an estimated cost of $1.2 million, subject to satisfactory negotiation of the final contract language; and

BE IT FURTHER RESOLVED, that the CEO and General Manager, or his designee, is hereby authorized to terminate the existing lease for the Dickinson Junction 115 kV facilities.

C. Purchase of Bowman Substation 230 kV Bus Work

Mr. Rudolph reported that the Bowman Substation is located on the Miles City-to-New Underwood 230 kV line. Basin Electric owns much of the 230 kV bus, including the 230 kV breakers. Slope Electric Cooperative (**Slope Electric**) purchased the portion of 230 kV bus that Upper Missouri owned. Basin Electric presently leases these 230 kV facilities and recovers the cost in the SPP tariff. The proposal is for Slope Electric and Basin Electric to terminate the lease and Basin Electric purchase this equipment. The net book value is approximately $260,000. Basin Electric would recover the cost in the SPP tariff.

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

R03.12-14-16 RESOLVED, that the CEO and General Manager, or his designee, is authorized to enter into a purchase agreement with Slope Electric Cooperative for the Bowman 230 kV bus at an estimated cost of $260,000, subject to satisfactory negotiation of the final contract language; and

BE IT FURTHER RESOLVED, that the CEO and General Manager, or his designee, is authorized to terminate the existing lease for the Bowman 230 kV facilities.

8. Office of General Counsel Report

Senior Vice President & General Counsel Mark D. Foss reported on the status of litigation involving the Cooperative. We've received word of verbal approval from the Region 8 of the Environmental Protection Agency (**EPA**), the Justice Department and the Wyoming Attorney General's office on the Laramie River Station (**LRS**) Best Available Retrofit Technology (**BART**) settlement. Once signed by EPA headquarters, Basin Electric and the other Missouri Basin Power Project (**MBPP**) owner participants would sign, at which point we would make a final request to Wyoming Governor Mead to sign the LRS BART settlement agreement.

LRS first received a Section 114 information request in September 2011. Another statute of limitations is about to pass and EPA has requested that Basin Electric extend the tolling agreement from December 31, 2016 to June of 2017.

Mr. Foss reported that Basin Electric, Minnkota Power Cooperative, Inc. (Minnkota) and the state of North Dakota won the *Heidinger* case before the Eighth Circuit Court of Appeals. This was the case challenging a Minnesota law prohibiting importing power from new coal-fired power plants into the state of Minnesota. We won the case and were also awarded attorney's fees in total of $1.3 million. While Minnesota chose not to appeal the case, it is appealing the award of attorney's fees.

He then discussed various different possible outcomes for the CPP given the incoming administration.

A. Application for Class A Membership of Members 1st; Applications for Class C Membership of Fergus, PRECorp, Tongue River and Mid-Yellowstone; Termination of Class A Membership of PRECorp

Mr. Foss reported that the Membership's approval of the Bylaw amendments at the 2016 annual meeting allows Members 1st Power Cooperative (**Members 1st**) to become a Class A Member of Basin Electric. As all of the requirements to become a Class A member set forth in the Basin Electric Bylaws have been met, he recommended that the Board authorize the issuance of a Class A Membership Certificate in the name of Members 1st and the termination of the Class A Membership Certificate of Powder River Energy Corporation (**PRECorp**).

He reported that Class C Membership Applications have been received from Fergus Electric Cooperative (**Fergus**); (2) PRECorp; and (3) Tongue River Electric Cooperative (**Tongue River**), which will be members of District #10 (Members 1st) and from Mid-Yellowstone Electric Cooperative (**Mid-Yellowstone**), which will be a member of District #8 (Upper Missouri). As these four cooperatives have all met the requirements set forth in the Basin Electric Bylaws to become Class C Members, he recommended that the Board authorize the issuance of Class C Membership Certificates in the names of Fergus, PRECorp, Tongue River and Mid-Yellowstone.

Although not required by the terms of the contract, Mr. Foss recommended the Board ratify the Assignment and Consent Agreement between PRECorp and Members 1st pursuant to which PRECorp has assigned to Members 1st its interest in the Wholesale Power Contract dated January 21, 1997, as amended, between PRECorp and the Cooperative.

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

R04.12-14-16 RESOLVED, that the Application for Class A Membership and for Electric Service submitted by Members 1st Power Cooperative is hereby accepted and approved.

BE IT FURTHER RESOLVED, that the Class A Membership of Powder River Energy Corporation is hereby terminated.

BE IT FURTHER RESOLVED, that the assignment by Powder River Energy Corporation to Members 1st Power Cooperative of its interest in and to the Wholesale Power Contract dated January 21, 1997, as amended, between Powder River Energy Corporation and Basin Electric Power Cooperative is hereby ratified.

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

R05.12-14-16 RESOLVED, that the Applications for Class C Membership and for Electric Service submitted by Powder River Energy Corporation, Fergus Electric Cooperative, Tongue River Electric Cooperative and Mid-Yellowstone Electric Cooperative are hereby accepted and approved.

9. Recess and Reconvention

At 4:50 p.m., President Peltier recessed the meeting until 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.

10. 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, Andy Buntrock, Eric Carufel, Tammy DeWitt, Erin Fox Dukart, Mike Eggl, Elizabeth Erhardt, Pius Fischer, John Frank, Dan Gallagher, Matt Greek, Steve Johnson, Kerry Kaseman, Becky Kern, Janet Kubisiak, Tom Leingang, Brian Larson, Jim Lund, Russ Mather, Tracey McBride, Gavin McCollam, Cris Miller, Mary Miller, Diane Paul, Mike Paul, Curt Pearson, Colleen Peterson, Dave Raatz, Kevin Solie, Susan Sorensen, Myron Steckler, Steve Tomac, Kevin Tschosik, Katrina Wald, Valerie Weigel and Michelle Wiedrich.

Also present were DGC Vice President David J. Sauer, East River director Alan Vedvei and Mountrail-Williams director Blaine Jorgenson.

11. Operations Report

Senior Vice President - Operations John Jacobs reported that there was one medical treatment and two DART incidents at LRS during the month.

He provided bus-bar costs for the coal-fired fleet (the Leland Olds Station (**LOS**), the Antelope Valley Station (**AVS**), the LRS and the Dry Fork Station (**DFS**)), 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. November generation for the owned and operated Basin Electric fleet came in at 2,069,613 MW compared to the budget of 2,411,797 MW, which is 14.2% under budget for the month. Year-to-date generation is 4.8% below budget.

Unit	Monthly Availability	Running Plant Capacity Factor (net)	Unit Rating	Comments
AVS #1	100%	95.1%	450 MW	
AVS #2	100%	93.0%	450 MW	
DFS	100%	101.2%	386 MW	Monitoring a leak.
LRS #1	95%	61.72%	570 MW	Forced outage 11/8/16 loss of all fuel controls. Forced outage 11/17/16 turbine EHC pipeline leaks.
LRS #2	85%	55.74%	570 MW	Scheduled outage 11/4/16 LP turbine bearing no. 5 oil leak.
LRS #3	87%	58.82%	570 MW	Scheduled outage 11/8/16 economizer tube leak repair. Forced outage 11/14/16 EHC spool piece failures A&B.
LOS #1	100%	75.61%	221 MW	
LOS #2	74%	83.68%	448 MW	Scheduled outage 11/12/16 turbine oil leak.

Mr. Jacobs presented photographs and discussed the feedwater heater wall tube leak. He reported that the Wyoming Infrastructure Authority (**WIA**) has requested another trailer for offices. PRECorp has a transformer where the power for the test station will be provided but it isn't large enough. PRECorp is planning to upgrade that transformer. The contract requires that we purchase the transformer but PRECorp is obligated to purchase it back minus depreciation at the end of the project. These costs will be charged to the WIA.

A. <u>DFS Catalyst Replacement</u>

Mr. Jacobs reported that DFS believes that it can maintain a 36-month planned outage cycle utilizing regenerated catalyst instead of new OEM catalyst. This would reduce DFS 2019 capital expenditures by $2.1 million and add 1,000 hours of potential operating life. Catalyst performance testing and dry storage is included in the overall cost. The project cost is $2.58 million versus the $4.68 million included in the 2017 budget. As the project is mandated by environmental regulations, Project Review Committee approval was not required.

The project scope involves the removal and shipment of the exhausted catalyst to a regeneration site, evaluation of a quality assurance/quality control test of the catalyst modules pulled during the spring DFS outage and sent to the vendor's facility in North Carolina, issuance of a purchase order for the regeneration of the remaining modules (at a cost of $1.4 million); shipment of the catalyst to DFS in

2019; replacement of layers three and four with the regenerated catalyst during the 2019 outage and shipment of the exhausted catalyst for cleaning and regeneration. He presented photographs comparing new, used and regenerated (after blasting with dry ice) SCR catalyst, as well as a photograph of the Kings Mountain Catalyst Regeneration Center.

Two hundred eighty catalyst modules have been shipped for regeneration and the evaluation of the effectiveness of the regeneration process is complete. He reviewed the schedule for the remainder of the project, which is scheduled for completion in October of 2019.

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

R06.12-14-16 RESOLVED, that replacement of the OEM catalyst at the Dry Fork Station with regenerated catalyst at an overall cost not-to-exceed $2.585 million is hereby approved; and

BE IT FURTHER RESOLVED, that the CEO & General Manager, or his designee, is authorized to approve and execute the required contracts.

B. Distributed Generation Update

Distributed Generation Manager Kevin Tschosik introduced Colleen Peterson, Compliance Program Specialist, who handles compliance in the Distributed Generation division.

He 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 Generation Station (**PGS**) and Lonesome Creek Station (**LCS**)) dropped during the month. November generation at the distributed generation facilities was as follows:

Unit	Monthly Availability	Monthly Generation	Unit Rating	Comments
Culbertson CT	93.35%	97 MW	97 MW	Ran for load demand.
DCS	99.46%	67,935 MW	300 MW	Photos of HRSG enclosure. Ran well for load demand. Presented photos of HRSG enclosure, which has been completed.
Groton #1	57.18%	688 MW	100 MW	Photos of Groton #1 generator circuit breaker disconnect, circuit breaker, PIG launcher, gas pipeline pigging single ring brush with magnet PIG, gauge plate PIG, double ring brush PIG, deformation tool,

				magnetic flux leakage tool, receive. Don't yet have data back. 15-day outage. Circuit breaker disconnect- corrosion on "B" phase.
Groton #2	100%	7,375 MW	100 MW	Ran for load demand.
LCS #1	87.21%	15,404 MW	45 MW	Ran for load demand and reliability. Completed fall outages and inspections. One small outage on unit #2.
LCS #2	94.22%	22,804 MW	45 MW	
LCS #3	96.03%	22,617 MW	45 MW	
PGS #1	93.46%	5,509 MW	45 MW	Ran for load demand and reliability. Engine inspections and boroscopes were done.
PGS #2	80.05%	3,364 MW	45 MW	
PGS #3	94.71%	4,459 MW	45 MW	
SMS #1	0%	0 MW	60 MW	Did not run.
SMS #2	0%	0 MW	60 MW	
WDG		2 MW	45 MW	

LCS ran in synchronous condensing 43.53 hours and PGC for 477.93 hours during November. There were 18 spinning reserve calls during the month.

PrairieWinds ND (PWND). Semi-annual maintenance is 96% complete.

PrairieWinds SD (PWSD). Annual maintenance at 60% complete. An emergency responder meeting was held.

The east-side peak occurred on November 21, 2016 at 11:00 hours. At that time, wind generation was as follows:

Wind Project	Load Factor during the Peak	Capacity Factor		Project Total
		Month	YTD	
Baldwin	74 MW	51%	44%	99 MW
Campbell County	76 MW	52%	44%	98 MW
Day County	97 MW	55%	51%	99 MW
Edgeley	12 MW	41%	31%	40 MW
Highmore	32 MW	43%	38%	40 MW

Iowa Wind	22 MW	45%	37%	45.1 MW
Other Projects (Chamberlain & Pipestone)	2 MW	25%	21%	3.4 MW
PWND	78 MW	51%	41%	123 MW
PWSD	144 MW	55%	44%	162 MW
Wilton	77 MW	47%	41%	99 MW
Total Monthly Wind Generation	614 MW	45%		800 MW
Average Capacity Factor		47%	47%	

C. Laramie River Station Plant Update

LRS Plant Manager Brian Larson reported that 57% of the LRS workforce has 10 or fewer years of experience. In the next 10 years, 36% of the LRS workforce will be eligible for retirement at age 62. A training program is being established with the assistance of the Human Resources division.

He reviewed safety statistics, year-to-date 2016 environmental compliance statistics and November and year-to-date 2016 production statistics.

As of November 30, 2016, Grayrocks Reservoir was at 4,403.8 feet Mean Sea Level or 99.3% full. LRS is trying to lower the reservoir level approximately one foot to be able to inspect the Morning Glory spillway. After the inspection, the reservoir will be allowed to refill. As of the same date, the LRS stockpile inventory contained approximately 2,251,827 tons or an estimated 94-day supply for operations at full load.

Projects planned for the April 8 to May 27, 2017 Unit #3 outage include replacement of air heater baskets and air-heater lube-oil skid, dry scrubber work, economizer inlet header, cooling tower switch gear, repair of circulating water piping, work on the cooling tower fan motor variable-speed drives and installation of new IK soot blowers.

Mr. Larson then presented photographs and discussed the new warehouse. He also presented photographs, schedules, budgets and actual costs of the activated carbon injections systems for Units #1, #2 and #3, the replacement of dust collectors 7 and 8, the main plant air dryer replacement, the Unit #1 north cascade floor replacement, emergency holding pond bank stabilization project to comply with the Coal Combustion Residue rule and the Unit #3 circulating water buildings A and B.

12. Risk Management Report

Manager of Commodity Risk Kerry Kaseman reported that the current average hedged price for peak east purchased power is $26.26/MWh in 2016 and $25.72/MWh in 2017.

The current hedged position for natural gas is $2.83 per dekatherm (**dkt**) for 2016, $3.09/dkt for 2017, $3.11 for 2018, $3.20 for 2019, $3.21 for 2020 and $3.22 for 2021. The current averaged hedge price of natural gas in storage inventory value is $1.96/dkt, the average sale price at the time of injection was $1.41/dkt and the average sale price at the time of withdrawal is $2.80.

He reviewed the Ventura Forward Curve which, as of December 1, 2016, was $3.27/dkt for 2017, $2.92/dkt for 2018, $2.75/dkt for 2019 and $2.74/dkt for 2020 and $2.76/dkt for 2021.

The November settled financial hedges for natural gas resulted in a loss of ($23,230). The total Mark-to-Market (**MTM**) for natural gas was a loss of ($5 million).

He reviewed the current hedged price for west surplus sales, which for the on-peak is $26.37 in 2016 and $28.08 in 2017 and for the off-peak is $22.42 in 2017.

He reviewed the Palo Verde On-Peak Forward Curve which, as of December 1, 2016, was $30.01/MW for 2017, $28.80/MW for 2018, $30.19/MW for 2019, $33.10 for 2020 and ended at $33.49/MW for 2021.

The November settled financial hedges for 85 MW of power resulted in a net gain of $4,350.

He reviewed the MTM power gain of $1 million, which does not include the negative ($27 million) MTM loss on one long-term physical contract.

He reviewed the current hedge position for diesel, which reflected an average 2016-hedged price of $2.17/gallon, $2.43/gallon for 2017 and $2.56/gallon for 2018. He reviewed the Energy Information Agency's (**EIA**) on-highway diesel price projections. The November settled financial hedges for diesel resulted in a gain of $22,161 on a 77,000-gallon diesel hedge. As of November 30, 2016, the diesel MTM was a gain of $297,000.

The aggregate settlement for all commodities for the month was $3,238 and $318,685 year-to-date, which does not include the MTM gain/loss on premiums and ineffective hedges. He then reviewed the MTM ($3.7 million) loss for all commodity hedges, which does not include the $27 million MTM loss on a physical long-term contract. He also reviewed the Cooperative's liquidity position.

13. Marketing & Asset Management Report

Manager of Marketing & Financial Analytics Valerie Weigel reported that EIA is projecting electric consumption for December 2016 through March 2017 to be 4% higher than last year, driven by temperatures that are projected to be 3% warmer than normal but still 13% cooler than the same period a year earlier. On the power side, more United States electricity is expected to be generated from coal than gas this winter, but the share of total annual generation from natural gas is forecast to exceed coal in 2016 and 2017.

In SPP, the average transacted load zone purchase price was $21.19 versus a budgeted price of $26.20. The average transacted sales price was $20.36 versus a budgeted price of $24.87. Despite a low allocation of Auction Revenue Rights in November, all day-ahead congestion was covered and produced a margin of approximately $400,000. Positive impacts were also seen on real-time congestion. The Brady 1 and Sunflower wind generation was added to the SPP resource fleet in November. The Lindahl and Brady 2 wind generation are expected to be added in December. Milton R. Young Unit #2 is still in outage and operational testing has begun on the new Pioneer units.

Montana load was optimized by serving through purchases for the first half of November, saving approximately $5.35/MWh; and serving through SPP for the second half of November as market conditions flipped.

Generation sales prices and load purchase prices for November were close to budget ranges with some variability by day. The November day-ahead average SPP load zone price was $21.08 and the November real-time average price was $25.61.

She reviewed the November hourly volumetric position, noting that Basin Electric held a long position for the first half of November, while the second half of November saw the position fluctuate based on market conditions and unit availability.

In the West, the average transacted sales price was approximately $19.95 versus the budget of $21.98. We were approximately 75% hedged going into November with hedges settling in the money. The Ault transmission line outage resulted in: significant decreases in sales opportunities as the front range of Colorado is a key market area for surplus sales; optimized physical hedges and daily sales at alternative western interconnection points; and reliability system conditions that resulted in significant derates on LRS #2 and #3 throughout the month.

The day-ahead on-peak average price was $21.07 and the day-ahead off-peak average price was $17.64.

In MISO, the average transacted load zone purchase price as $19.78 versus a budgeted price of $25.69. The average transacted sales price was $20.30 versus a budgeted price of $21.65. Economic derates continued in MISO, including Walter Scott #4. Unit costs ranged from $12 to $15/MWh.

She then reviewed the October generator profits and losses.

Resource Contingency. Lead Business Development & Scheduling Dan Gallagher reported that the SPP Market requires long-term resource adequacy, spinning reserves, operating reserves, regulation up, regulation down and energy must offer.

What does the market actually require a load-serving entity to provide versus being able to procure from the market?

Resource adequacy is the ability to meet electric usage demands with sufficient owned or purchased generating capacity or "steel in the ground". It is expressed in terms of reserve margins. A reserve margin is the amount of excess generating capacity available to meet peak demand. SPP requires that each load-serving member maintain a 12% planning reserve margin. This was reduced from 13.6% in April of 2016.

He outlined the various short-term operating reserves available: spin, supplemental, regulation up and regulation down. These are market products that may be purchased on a daily basis, but can be offset from available resources. Spin is the portion of contingency reserve consisting of resources synchronized to the system and fully available to serve load. Supplemental is the portion of contingency reserve consisting of on-line or off-line resources capable of being synched to the system and fully available to serve load within 10 minutes. Regulation Up is the resource capacity that is available for the purpose of providing regulation up deployment and is capable of responding to a four-second set point/signal from SPP. Regulation Down is the resource capacity that is available for the purpose of providing regulation down deployment and is capable of responding to a four-second set point/signal from SPP.

Mr. Gallagher then discussed ancillary product pricing and noted that each day an asset owner must offer enough resources into the market to cover 90% of its peak hourly load for the day. If a market participant has offered all of its available resources for an asset owner with a commitment status of market, self or reliability, they are also deemed to be in compliance. If the asset owner is not in compliance, a penalty is assessed.

2017 Basin Electric Surplus Sales Hedge Plan. Of the targeted $23.1 million revenue, $16.8 million has been secured or roughly 73% of the plan. Of the targeted 1,058,800 MWh, 657,900 MW have been secured or 62% of the plan. If the remainder of the plan was filled at today's prices, we would be securing a revenue of $26.2 million versus the $23.1 million notional value of the plan.

2017-2021 Basin Electric Natural Gas Hedge Plan. Of the targeted $95.0 million expenses, $73.7 million has been secured or roughly 78% of the plan. Of the targeted 32,346,620/mmbtu, 25,007,500 have been secured or 77% of the plan. If the remainder of the plan was filled at today's prices, we would be securing an expense of $95.7 million versus the $95.0 million notional value of the plan.

14. Cooperative Planning Report

A. PURPA Assignment

Vice President of Cooperative Planning Dave Raatz reported that publication of the public notices regarding the Public Utility Regulatory Policy Act assignments was done in November. To date, there have been five requests for copies of the proposed implementation plan (from other utilities). Staff is working with the Legal Department on a response to a comment that was received from the Clean Up the River environmental group. The public comment period ends in December. After all comments have been received, staff will determine if public meetings are required, will respond to direct questions and will make a Federal Energy Regulatory Commission filing during the first quarter of 2017.

B. Minnkota Activity Update

Mr. Raatz reported the following current schedule on the proposed Minnkota transaction: modeling and the economic analysis of joint operations with Minnkota will take place through December 2016, a directional discussion and decision will take place in January and early February, Basin Electric membership discussion will follow and agreement development is scheduled from late January through April 2017, with agreement execution during the spring or summer of 2017 with joint operations starting in the summer of 2018.

Minnkota has scheduled a special member meeting for February 17, 2017 and the Minnkota annual meeting will take place April 7, 2017.

In order to get an idea of what a bigger Basin Electric would look like, Mr. Raatz reviewed each organization's load breakdown, monthly load pattern, combined member sales, size and 2016-generation portfolios. He reviewed Basin Electric's MISO surplus/deficit and Minnkota's load management operations. He then reviewed the combined MISO surplus/deficit with Minnkota load management operations (Case 1) and with Basin Electric accreditation of Minnkota's load management (Case 2).

Preliminary economics should be available by late December. Mr. Sukut noted that this matter had been delayed due to uncertainties that were created by the CPP.

C. Nemadji Trio Energy Center

Mr. Raatz reviewed issues which have previously been approved in negotiations regarding the Nemadji Trio Energy Center (**NTEC**). Throughout negotiations, Basin Electric's Board and staff have expressed concern that the facility's operating agent may be a minority owner. He reviewed Minnesota Power (**MN Power**) November 29 options, investment costs of MISO options, MN Power December 4 options, December 7 conference call options and noted that the CEOs of all three organizations are currently scheduled to meet on December 21. MN Power has requested a 45-day extension to find a 95 MW off-taker. Basin Electric is opposed to a delay. MN Power has suggested a smaller version of NTEC, which is not acceptable to Basin Electric. Therefore, Mr. Raatz suggested that staff continue with previously approved project, size, timing, etc. and see if MN Power will continue with project or terminate the pre-development agreement.

D. Tri-State Contract Discussion

Mr. Raatz reviewed the timeline of meetings held with Tri-State Generation & Transmission Association, Inc. (**Tri-State**) regarding Tri-State's Wholesale Power Contract with Basin Electric. Tri-State has not agreed to extend its contract to 2075. As a result, Tri-State's current contract term is 2050. As a result, Tri-State is not receiving the contract extension credit.

15. Recess and Reconvention

At 12:10 p.m., President Peltier recessed the meeting until 1:00 p.m. December 15, 2016, at which time the meeting reconvened with President Peltier continuing to preside and Secretary Gary C. Drost continuing to keep the minutes.

16. 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, Kelly Cozby, Tammy DeWitt, Erin Fox Dukart, Pius Fischer, John Frank, Matt Greek, Steve Johnson, Becky Kern, Mark Kinzler, Janet Kubisiak, Jim Lund, Shawnel Maxwell, Gavin McCollam, Sally Meier, Cris Miller, Darla Miller, Mary Miller, Diane Paul, Mike Paul, Curt Pearson, Dave Raatz, Jean Schafer, Kevin Solie, Susan Sorensen, Myron Steckler, Katrina Wald, Greg Wheeler, Michelle Wiedrich and Mike Zimmerman.

Also present were DGC Vice President David J. Sauer, East River director Alan Vedvei and Mountrail-Williams director Blaine Jorgensen.

17. Cooperative Planning, continued

A. Tri-State Contract Discussion, continued

Mr. Raatz noted that currently Basin Electric delivers to Tri-State's Colorado/Wyoming loads at LRS. Basin Electric has proposed to move the delivery points to Tri-State to Ault, Stegall and Story, which would make the Tri-

State deliveries more comparable to the deliveries to the balance of the membership. This results in reduced revenue from Tri-State to Basin Electric of approximately $1 million per year.

Basin Electric can also adjust the Contract Rate of Delivery (**CROD**) delivery patterns to better fit Tri-State's current Colorado/Wyoming loads. This will result in no change to the annual Class A demand and energy sales to Tri-State, but will result in reduced net revenue to Basin Electric of approximately $125,000 per year.

He noted that the Tri-State wholesale power contract also needs to be revised to include the language "or principal repayments of Seller" set forth in the other member contracts.

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

R07.12-14-16 BE IT HEREBY RESOLVED, that the CEO and General Manager, or his designee, is authorized to execute modifications to the Tri-State Generation & Transmission Association, Inc. Wholesale Power Contract that provides for deliveries based on East/West Interconnection boundaries rather than state boundaries, deliveries of newly shaped Contract Rate of Delivery Patterns, for the assumption of responsibility for associated transmission losses to the delivery points, and include appropriate debt service recovery language.

B. Member Contract Review

Mr. Raatz reported that, of the new Montana members, Yellowstone Valley, Mid-Yellowstone and Tongue River have historically contributed equity to Basin Electric through Central Montana Electric Power Cooperative, Inc. (**Central Montana**) and thus, have no parity adder.

Fergus Electric never had a Basin Electric/Western Area Power Administration delivery point and so will appropriately be assessed a parity adder.

What about Park Electric Cooperative (**Park**) and McCone Electric Cooperative The 2.72-mill adder was approved by the Board in May of 2004, began in July of 2008 and ends in June of 2023. Staff feels it is appropriate to eliminate the parity adder on Park and McCone going forward because they did contribute to Basin Electric through Central Montana. From January 1, 2017 through June 30, 2023, this amounts to approximately $462,000 per year.

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

R08.12-14-16 RESOLVED, that the Board of Directors authorizes the CEO and General Manager, or his designee, to execute an amendment to the Wholesale Power Contract with Central Montana Electric Power Cooperative, Inc. to eliminate the 2.72-mill parity adder for Park Electric Cooperative and McCone Electric Cooperative effective January 1, 2017.

C. Long-Term Decision Timeline

Mr. Raatz noted that this report is to address the issues in order to answer the question: How long can we wait before we make power supply decisions.

Director of Utility Planning Becky Kern reported that Leidos, EVA and The Brattle Group have been hired to do various analysis, Requests for Proposals were issued each year to learn what is available in the market, new load forecasts were created each year (and in some cases, each quarter) and a great deal of work has been done to determine the cost of a new resource in order to respond to this question.

Sixty-five percent of the Cooperative's winter and summer nameplate capacity portfolio is from owned resources and 35% is from purchased power agreements. If Minnkota were to join Basin Electric and the Cooperative executed a purchased power agreement with Minnkota, our purchased power would increase to 45%.

The Cooperative's strategy has been to monitor load growth and not overbuild if growth does not materialize, build into a larger unit to gain economies of scale and take advantage of lower market conditions for as long as possible before committing to a long-term asset.

Environmental Services Director Mike Paul discussed the environmental/regulatory landscape for the existing coal units, regarding challenges to future operations. He also reviewed the environmental regulatory timeline for coal generation over the past eight years and acknowledged the Board and Basin staff, as we have, and continue, to successfully meet these challenges.

Senior Environmental Project Specialist Cris Miller discussed the regional haze rules which will have a big impact on our resources in the future, as well as project development of new resources. He noted the end goal of the Regional Haze program is to reduce visibility impact in Class I Areas to natural conditions by 2064. He also described typical permitting components and provided a listing of keys to successful permitting from the Environmental Services perspective.

Engineering Services Director Gavin McCollam reported on new technologies and discussed new resource development timelines. Resource alternatives include baseload, intermediate, peaking, renewable and fuel conversion. A total of 65 different alternative configurations are being reviewed.

Ms. Kern then reviewed the need/alternatives/decision timeline, noting that in previous discussions that a new resource is expected to be needed in Montana by 2026, in SPP by 2024 and in MISO by 2023. We plan to move 240 MW from west to east, assuming the Stegall DC Tie continues to operate or is replaced. The objective is to identify the least-cost, long-term power supply for the membership using a view of the future and not a view of the last six to 12 months. In order to meet these potential new Resource timelines, a decision on the strategy for meeting future power supply needs to be made between 2019 and 2012 in Montana (WECC-NWPP), in 2017 for MISO zone 1, between 2018 and 2022 for SPP to meet future load growth and potential replacement of LOS #1 and #2 and between 2025 and 2029 for the potential replacement of AVS.

18. Engineering & Construction Report

A. Project Funding Chart

Senior Vice President-Engineering & Construction Matt Greek reported that four Basin Electric contracts totaling $16.7 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 Selective Non-Catalytic Reduction Budget Amendment

Senior Project Manager Jim Lund reported that the selective non-catalytic reduction (**SNCR**) project was required to comply with North Dakota Regional Haze regulations by April of 2017. The project was approved by the Board of Directors in July 2014 at a cost of $9.34 million for Unit #1 and $25.96 million for Unit #2. Detailed design and procurement was done from August 2014 through June of 2015; construction took place July 2015 through June 2016; commissioning took place June through September of 2016; the project was turned over to LOS Operations in October 2016 and the project will be closed out in January 2017.

Unit #1 is performing 13% below and Unit #2 is performing 28% below the April 2017 permit restrictions. Urea receiving, storage and handling equipment, water treatment/power supply/compressed air systems are located inside the new SNCR building, which also provides the ability to process both liquid and dry urea.

There are 16 injection locations in the Unit #1 furnace and 28 in the Unit #2 furnace, which provide the ability to operate at low-, mid- and high-load conditions. The system is controlled by a distributed control system and is integrated with furnace combustion operation. There were no safety incidents or lost-time incidents during this project. Mr. Lund presented photographs and discussed the new SNCR building, urea metering skid and urea distribution skid.

He noted that construction was delayed three months due to late deliveries of owner-supplied equipment and late vendor electrical design submittals. The SNCR building was installed per the original schedule (December 2015).

Commissioning was delayed one month as more field support time was needed than anticipated to integrate components into the plant control system, urea process equipment quality issues and the LOS operations acceptance protocol.

He reviewed the project cost summary, which results in budget exceedances of $172,249 for Unit #1 and $219,508 for Unit #2. He recommended that budget amendments increasing the project amounts be adopted for each unit.

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

R09.12-14-16 RESOLVED, that the Project #W01148 budget for LOS Unit 1 selective non-catalytic reduction be increased by $200,000 for cost overruns to a new contract total of $9,540,545; and

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

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

R10.12-14-16 RESOLVED, that the Project W01051 budget for the LOS Unit #2 selective non-catalytic reduction be increased by $250,000 for cost overruns to a new contract total of $26,208,889; and

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

C. LRS Selective Catalytic Reduction Project Update

Mr. Lund reported that design and specification development activities are proceeding on schedule. Equipment contracts for the project are currently $20 million under budget. The CCC Group completed the fall 2016 outage scope work on time and is on track for completion of selective catalytic reduction (**SCR**) foundation work by January. There are no anticipated Basin Electric contracts for housing. Basin Electric will provide housing contacts and availability to contractors on a monthly basis.

Bids will be received for the SCR general works contract package in December. In January, the compressed air, auxiliary transformer and 13.8 kV switchgear contracts will be awarded. The bulk warehouse demolition will take place in February. The SCR general works contract will be awarded in March. SCR general work contract mobilization and start of SCR steel and ductwork deliveries will take place in April. He then reviewed the project cost summary.

D. Award of LRS SCR Structural Steel Supply Contract

Mr. Lund reported that the scope of this contract is for the SCR and ductwork support steel, SCR enclosure siding steel and platforms, stairs and handrail, a total of over 6,000 tons of steel. The project budget is $13,342,950. All of the six pre-qualified bidders submitted bids. After review, he recommended the contract be awarded to Prospect Steel Co. for $5,946,130, which provides a budget margin of $7.4 million due to favorable commodity and steel prices, available shop space and lower SCR reactor height versus the estimate.

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

R11.12-14-16 RESOLVED, that Contract #723545, LRS SCR Structural Steel, be awarded to Prospect Steel Co. in the amount of $5,946,130; and

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

E. Award of LRS SCR Construction Management Contract

Mr. Lund reported that this project's scope of work includes the construction management, technical field support, safety management, project controls and material expediting on a time-and-material basis. Basin Electric will provide the site manager and administrative and document control. The budget is $6.4 million.

He recommended the contract be awarded to Sargent & Lundy (**S&L**) for $6.1 million due to Basin Electric's experience with S&L construction management processes and assigned personnel, financial and schedule benefit to the project by having the engineering and construction management services performed by the same company. He noted that S&L's proposed rates are comparable with construction management rates for recent Basin Electric projects. The agreed fee contains risk terms up to 7% based on quarterly grading and end-of-job deliverables.

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

R12.12-14-16 RESOLVED, that the LRS SCR Construction Management contract be awarded to Sargent & Lundy in the amount of $6.1 million; and

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

F. LRS Units #2 and #3 SNCR Project Update

Mr. Lund reported that this Phase 2A Capital Project is in the pre-project development stage. Staff is evaluating the SNCR process equipment bids and has issued bids for the water treatment equipment. The preliminary engineering and design and updated Phase 1 cost estimate have been completed.

Board consideration of the Phase 2 capital project and awards for engineering and SNCR process equipment contract will be requested in January. Unit #3 injection port locations will be identified in February and will be installed during the April 2017 spring outage.

G. Dickinson Substation Upgrades Project Budget Amendment

Electrical Engineer II Stephen Farnsworth reported that this project was originally called "Dickinson Capacitor Additions" and was approved by the Board in September 2011 at an estimated cost of $2 million. It was required due to change of system requirements for the Dickinson Substation. Capacitor additions are no longer required, the project scope has been redefined and the project has been renamed "Dickinson Substation Upgrades".

The redefined scope includes the replacement of two 230 kV breakers, the addition of one 230 kV breaker, the addition of six potential transformers, modification of the 230 kV bus for increased safety, relay panel and configuration upgrades, RTU SCADA upgrades, evaluation of the DC system for redundancy, evaluation of the AC system for capacity and arc flash and a temporary 230/115 kV transformer.

Mr. Farnsworth presented a map of the Dickinson Substation site and locations of the modifications. Project engineering will take place through April 2017, procurement from January through May 2017 and construction from April through December 2017. The Class 3 estimated project cost is $6,155,658 for engineering, overheads and miscellaneous, construction, materials and contingency. He recommended approval of the Dickinson Substation Upgrades project.

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

R13.12-14-16 RESOLVED, that the budget for the Dickinson Substation Upgrades Project, as presented at this meeting of the Board of Directors, is hereby increased by $4,200,000 to a new total of $6,200,000; and

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

19. Human Resources Update

Senior Vice President-Human Resources Diane Paul reported that the average age of the Basin Electric and DGC 2016 retirees is 61 years and the average service of the 2016 retirees is 29 years. In 2017, 132 employees (mainly at headquarters) will be 62 or older. In 2017, 592 employees (at headquarters, DGC and LRS) will be 55 or older. In the next 10 years, 750 employees, 169 of which are supervisors, will reach the normal retirement age of 62.

She reviewed the number of retirements from 2008 through 2016 and noted that since September of 2014, 63% of our employees are new to their position. Programs and initiatives to educate the newer employees include a live-stream educational series entitled "People. Power. Purpose", apprenticeship programs, the "Building Cooperative Connections" initiative, the BE Leaders Program and the new employee orientation program.

In 2017, the Human Resources Department will conduct a review of the Cooperative's benefits program to tailor them to the demographics of the Basin Electric corporate family, create a job-shadowing program and continue to expand medical services to encourage a healthy workforce.

A. Safety Update

Safety/Occupational Health Administrator Kelly Cozby reviewed the Headquarters "Our Power, My Safety" focus card participation from 2014 to present, noting a record high response (83%) in November. Final edits are being made to the Safety Perception Survey presentation. Continuous Improvement Team #4, Safety Metrics, is working on finalization of the volunteer list, workshop dates and an incentive program update.

20. Communications & Administration Report

Senior Vice President of Communications & Administration Mike Eggl reported that the review of Board policies is going well. The fiscal policy was reviewed in October and no revisions were recommended. Barring any proposed revisions by the Board, it will be recommended for reaffirmation. Senior Vice President of Financial Services Steve Johnson noted the fiscal policy contains 3% margin language, and that he would like an opportunity for further review in order to provide justification for moving away from the specific 3% margin number. Director Drost agreed that the 3% margin requirement should be removed from the policy. The fiscal policy will be amended and presented to the Board for approval next month.

Mr. Eggl distributed the diversity policy for the Board's review and noted that he will request reaffirmation in January. He then reviewed the Board policy review schedule.

He will invite Elizabeth Gore and Jon Hrobsky from Brownstein, Hyatt, Farber and Schreck to the January Board meeting for an in-depth look at the new administration's cabinet.

Legislative Representative Jean Schafer reported that the topics of discussion during the Lignite Energy Council Fall/Winter Fly-In were coal regulations and the stream buffer rule, as well as potential Department of Energy Allam Cycle funding.

She reported that, pending several hurdles, there is the potential for up to $7 million per biennium from the state of North Dakota for coal technology funding.

Key goals for the North Dakota legislative session include the DGC tax proposal and revisions to the Public Service Commission siting statute. In Iowa, legislation is pending dealing with line personnel safety, the "move-over law", tree trimming, one call, tax exemptions on geothermal generation and the Duane Arnold Energy Center. Legislation of interest to the Cooperative in Wyoming deal with net metering and taxes.

In South Dakota, Initiated Measure 22 sets a $100 limit on the amount each legislator may receive from any one organization. Most states already have some sort of similar restrictions. Basin Electric had to cancel its legislative pre-session dinners in South Dakota because the legislators didn't understand the impact from this initiated measure.

In a great offensive strategy, a pending Minnesota bill would acknowledge that cooperatives are subject to local (as opposed to state) control. This would clarify for the Minnesota Public Utilities Commission and Department of Natural Resources that cooperatives are locally controlled and exempt from their regulation.

He noted that all states in the Cooperative's service territory have legislative sessions this year.

A. Communications & Creative Services

Vice President of Communications & Creative Services Mary Miller reviewed the Communications & Creative Services planning's 2016 accomplishments and what they expect in 2017.

The results of the annual meeting survey were very positive. Successes included the new managers' orientation, the preconference, the government action panel, the CEO report and the social and banquet. Opportunities for improvement included tightening of the speeches and videos, fewer scripted speeches, more dynamic conversations and more opportunities for audience engagement.

She then played the holiday ad developed for member cooperatives.

21. Financial Services Report

Senior Vice President & Chief Financial Officer Steve Johnson reported that Everett Dobrinski had been re-elected chairman of CoBank and reported on the meetings with banks and rating agencies in New York. All three agencies gave recognition to austerity measures and the dollar amount we've been able to save throughout the course of the year. Our primary focus is to get our Moody's Investor Service (Moody's) rating back to at least an A2 so that we'd have a strong argument for why our commercial paper should go back to a P1 rating. It will more than likely take a year or more for that to happen.

Senior Financial Analyst Katrina Wald has developed a model that looks at DGC's 20-year discounted cash flow so as to determine DGC's value in the market place. Mr. Johnson and Susan Sorensen had a conversation with the Royal Bank of Canada (**RBC**) about having RBC review our model and do an independent assessment of what they feel DGC would be worth to an unrelated third party.

Director Pearson said that, from a strategic perspective, staff's recommendation to meet with the banks and rating agencies every six months is a good one. All mentioned the importance of having directors there.

The consolidated year-end net income after tax is projected to be $62.3 million, which includes $11.5 million of deferred revenue (which could deplete our deferred revenue account).

A. DGC Minimum Equity

Mr. Johnson noted that there really isn't incentive for the lenders not to agree to some form of minimum equity as all of these DGC lenders are all also holders of Basin Electric indenture notes. We need to remind them that to fund a DGC equity infusion, Basin Electric would have to borrow money to purchase the DGC common stock, which just puts added leverage on Basin Electric's financials. Staff will work with the lenders over the next few weeks to get over this hurdle. As things currently stand, the banks have suggested a 90-day waiver of the (quarterly) requirement to maintain the minimum equity in DGC.

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

R14.12-14-16 RESOLVED, that the CEO and General Manager of the Cooperative is authorized to execute and deliver Amendment No. 1 to the Note Purchase Agreement by and among the Cooperative (as guarantor), Dakota Gasification Company and the note holders substantially in the form presented to this meeting of the Board of Directors with such changes as he finds to be in the best interests of the Cooperative, such finding to be conclusively demonstrated by his execution of the amendment.

Mr. Johnson also noted there is also a minimum equity provision in the DGC revolving credit agreement with the RBC.

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

R15.12-14-16 RESOLVED, that the CEO and General Manager of the Cooperative is authorized to execute and deliver Amendment No. 2 to the Credit Agreement by and among the Cooperative (as guarantor), Dakota Gasification Company and the Royal Bank of Canada substantially in the form presented to this meeting of the Board of Directors with such changes as he finds to be in the best interests of the Cooperative, such finding to be conclusively demonstrated by his execution of the amendment.

B. Accounting Report

Senior Accounting Analyst Darla Miller reported that the November 2016 Statement of Operations reflects an estimated net margin of $24.7 million compared to the budgeted net margin of $9 million for a favorable variance of $15.7 million. The net margin last month was $20.2 million and the margin for November of 2015 was $4.8 million.

Member sales were approximately $0.3 million higher than budget, which include the October actualization of $3.0 million. November sales are estimated to be $2.7 million less than originally forecasted. A negative volume variance of $16.3 million was offset by a positive pricing variance of $13.6 million.

Surplus sales were approximately $5.5 million lower than budget and includes the October actualization of $0.6 million. November sales are estimated to be $6.1 million less than originally forecasted. A negative volume and a price variance of $4.6 million and $1.5 million, respectively, were experienced.

Other electric revenue for November was $5.8 million compared to the budget of $3.1 million. This favorable variance can be primarily attributed to $3.7 million in liquidated damages to compensate for SunEdison's nonperformance under the Antelope Hills Project agreement.

Ms. Miller then reviewed operations expenses, maintenance expenses, year-to-date consolidated net income/loss, changes to the balance sheet and month-end cash. Year-to-date, the Basin Electric family has consolidated earnings of $41,026,509.

Basin Electric's November equity-to-asset ratio was 18.4% compared to 18.2% in October.

The November equity-to-capitalization ratio using the Moody's methodology (both without the consolidation entry for The Coteau Properties Company) was 21.7% compared to 21.6% in October.

The November equity-to-capitalization ratio based on indenture requirements for patronage distribution was 22.1% compared to 21.7% in October.

C. 2017 Operating & Capital Budget Approval

Manager of Financial Planning & Forecasting Andy Buntrock reviewed the changes to the operating budget from last month, resulting in a projected 2017 year-end, before-tax margin of $163.05 million.

The Basin Electric share of 2017 capital projects total $211.4 million with a cash flow of $68.2 million. Prior projects total $207.3 million, resulting in a total 2017 capital cash flow of $275.5 million.

The 2017 capital expenditures cash flow include $40.2 million for Dakota Coal Company (**DCC**), $99.6 million for DGC and $275.7 million for Basin Electric and the PrairieWinds subsidiaries for a total of $415.5 million compared to the 2017 financial forecast of $473.3 million.

The budgeted 2017 consolidated net income after tax is $69.6 million, a decrease of $7.5 million.

Mr. Buntrock then presented the resolution and recommended its approval.

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

R16.12-14-16 RESOLVED, that the 2017 Operating and Capital Budgets for Basin Electric Power Cooperative are hereby approved.

D. Property Insurance Renewal Update

Manager of Risk & Insurance John Frank reported that 2015 represents the first time the insurance industry has reported three consecutive years of underwriting profit since the 1970's. The loss ratio in 2015 was 99.6%; in 2014 was 97.2% and in 2013 was 96.7%. 2016 has seen a number of catastrophes including the Fort McMurray, Canada wildfires, earthquakes in Ecuador and Japan, flooding in the United States and continental Europe and Hurricane Matthew. Despite rate competition, insurers remain financially strong. The policyholder surplus stands in excess of $676 billion. The policyholder surplus is essentially the equivalent of the industry's net worth and a reliable indicator of its ability to pay claims.

Organizations that achieve the best results are the ones most able to demonstrate their ongoing commitment to proactive risk management.

This property renewal is effective December 1, 2016 and covers Basin Electric and all of its subsidiaries for generation, DGC-business income, DCC/Montana Limestone Company/Wyoming Lime Producers for business income and the MBPP. Insurable values total $13.28 billion, a 3% increase over last year. The renewal cost is $9.18 million, which is a decrease of 0.17% from last year. With the exception of 2013 (flat rate) and 2012 (15.02% rate increase), all of the rate changes since 2010 have been decreases.

The electrical generating plants and transmission and distribution properties have a $1 million per occurrence deductible, except a $1.5 million deductible for the GE7FA turbine unit at the DCS.

DGC has a $5 million per occurrence deductible, with a time element: a 30-day equivalent contribution deductible, per occurrence, subject to a maximum deducible of $15 million for property damage and time element combined, per occurrence.

Mr. Frank then reviewed the insurance carriers for the property/boiler insurance program.

He reported that our lead carrier, FM Global, is a mutual company owned by its customers and has recently announced a surplus distribution. Basin Electric's share of this distribution is $809,557. The surplus distribution to Basin Electric in 2015 was $750,683; in 2014 was $796,510; and in 2013 was $714,828. The DGC builder's risk loss should not affect the operating property insurance coverage.

22. Directors' Reports

Director Thiessen thanked Mr. Sukut for attending Upper Missouri's annual meeting.

Director Gilbert reported that the Corn Belt Power Cooperative (**Corn Belt**) directors and managers are frustrated with the rate increase and other things. Last month, a couple managers received an announcement that they were getting self-generation. He thanked Mr. Sukut for coming to speak at the Corn Belt managers meeting next week.

Director Brekel said he enjoyed the Mid-West Electric Consumers Association (**Mid-West**) meeting and thanked Ken Rutter for his presentation.

Director Drost reported he had been the delegate to the Midwest annual meeting. He complimented Director Brekel, who did a nice job leading the meeting.

23. ND Statewide 2017 Director & Alternate Director

Mr. Peltier noted that a director and alternate director are needed to represent Basin Electric on the North Dakota Association of Rural Electric Cooperatives (**North Dakota Statewide**). After discussion, it was moved by Director Pearson, seconded by Director Drost and carried that Directors Thiessen and Presser serve as director and alternate director, respectively, on the North Dakota Statewide board of directors.

24. ND Statewide 2017 Annual Meeting Delegate & Alternate

Mr. Peltier noted that a delegate and alternate are needed to represent the Cooperative at the North Dakota Statewide annual meeting. After discussion, it was moved by Director Drost, seconded by Director Baker and carried that Directors Thiessen and Presser serve as delegate and alternate, respectively to the North Dakota Statewide 2017 annual meeting.

25. SD Statewide 2017 Annual Meeting Delegate & Alternate

Mr. Peltier noted that a delegate and alternate are needed to represent the Cooperative at the South Dakota Rural Electric Association (**South Dakota Statewide**) annual meeting. After discussion, it was moved by Director Pearson, seconded by Director Baker and carried that Directors McQuistion and Pearson serve as delegate and alternate, respectively to the South Dakota Statewide 2017 Annual Meeting.

26. NRECA 2017 Annual Meeting Delegate & Alternate

Mr. Peltier noted that a delegate and alternate are needed to represent the Cooperative at the National Rural Electric Cooperative Association (**NRECA**) 2017 annual meeting. After discussion, it was moved by Director Presser, seconded by Director McQuistion and carried that Directors Gilbert and Thiessen serve as delegate and alternate, respectively to the NRECA 2017 Annual Meeting.

27. Date and Time of Next Board Meeting

President Peltier noted that the next regularly scheduled meeting of the Board of Directors will take place on January 10, 2017.

28. Adjournment

President Peltier adjourned the meeting at 4:40 p.m.

Gary C. Drost
Secretary-Treasurer