Approved November 7, 2016

Basin Electric Power Cooperative
Bismarck, North Dakota

Minutes of the Regular Meeting of the Board of Directors
October 11-13, 2016

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The Regular Meeting of the Board of Directors of Basin Electric Power Cooperative (the **Cooperative** or **Basin Electric**) was held at the headquarters building, 1717 East Interstate Avenue, Bismarck, North Dakota, beginning on October 11, 2016 at 2:00 p.m. CDT.

1. Call to Order

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

2. Roll Call

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

Donald E. Applegate	Paul Baker
Leo Brekel	Gary C. Drost
Charles Gilbert	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 Tracie Bettenhausen, Eric Carufel, Tom Christensen, Tammy DeWitt, Chad Edwards, Mike Eggl, Matt Greek, John Jacobs, Steve Johnson, Kerry Kaseman, Becky Kern, Anine Lambert, Joe Leingang, Deb Olafson, Mike Paul, Dave Raatz, Ken Rutter, Susan Sorensen, Steve Tomac, Kevin Tschosik, Valerie Weigel and Michelle Wiedrich.

Also present were Dakota Gasification Company (**DGC**) Vice President David J. Sauer, East River Electric Power Cooperative (**East River**) director Galen Grant and Corn Belt Power Cooperative (**Corn Belt**) manager Ken Kuyper.

3. Approval of the Agenda

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

4. Approval of the Minutes

The minutes of the September 13-14, 2016 Regular Meeting of the Board of Directors were presented and after an opportunity for corrections, it was moved by Director Brekel, seconded by Director Pearson and carried that the minutes be approved as presented.

5. General Manager's Report

General Manager Sukut reported that neither Paul Baker nor he was able to attend the Western Fuels Association (**WFA**) board or annual meetings, so Fuel & Transportation Supervisor Joe Leingang attended as the Cooperative's delegate.

6. Western Fuels Report

Mr. Leingang reported on the WFA, Western Fuels-Wyoming (**WF-WY**) and Western Fuels Service Corporation board and annual meetings which were held in Las Vegas to coincide with the National Mining Association (**NMA**) annual conference. CEO Meri Sandlin has a good relationship with NMA President & CEO Hal Quinn and he and his staff have an appreciation for cooperatives and G&Ts.

As to the election of WFA officers, Dave Geschwin was re-elected president, Paul Baker was re-elected vice president, Tony Casados was re-elected secretary-treasurer and Stuart Lowry was re-elected vice secretary-treasurer.

WFA had a small patronage assignment. He noted that Ms. Sandlin is doing a very good job for WFA.

In June, WFA devoted an entire strategic planning session to reformulation of the management fee that each member pays to WFA.

For 2017, Laramie River Station (**LRS**) nominated approximately 6.5 million tons and the Dry Fork Station (**DFS**) nominated approximately two million tons. Basin Electric and the Missouri Basin Power Project (**MBPP**) pay approximately 61% of WFA's costs. DFS has no rail operations and it didn't seem fair that the DFS pays the same per-ton rate as LRS, which has significant rail operations. Mr. Leingang reported that if Tri-State pulls the tons from Craig and Nucla and DFS is entitled to a lower rate, it follows that the average rate for the other customers will increase. The WFA board asked for a more nuanced "differentiated cost of service" approach and that was the most important aspect of the meeting. It is obvious that everyone else is implicitly acknowledging that their rate will increase, including MBPP/LRS. The net to Basin Electric and to Tri-State is that both would be the beneficiaries of these initiatives inasmuch as they have been paying the greatest share of WFA cost of service all along.

The following officers were elected at the 28th annual meeting of WF-WY: Paul Sukut-president; Mike McInnes-Vice President; Rick Gordon-Secretary-Treasurer; and Paul Baker-Vice Secretary Treasurer.

7. Office of General Counsel Report

Senior Vice President & General Counsel Mark D. Foss provided an update on the status of legal matters concerning the Cooperative.

A. Approval of Notice of 2016 Basin Electric Annual Meeting

Mr. Foss presented and reviewed the Notice of the 2016 Basin Electric Annual Meeting, which includes the proposed Bylaw amendments recommended by the 2016 Bylaw Review Committee, and recommended that it be approved. After discussion, it was moved by Director Drost, seconded by Director Pearson and carried that the following Resolution be adopted:

R01.10-11-16 RESOLVED, that the 2016 Notice of Basin Electric annual meeting presented to this meeting of the Board of Directors is hereby approved.

B. Selection of Delegates to Subsidiary Annual Meetings

Mr. Foss reported that the annual shareholder meetings of DGC, Dakota Coal Company, PrairieWinds ND 1, Inc., PrairieWinds SD 1, Inc. and Basin Cooperative Services will be held in December. He noted that historically, the Basin Electric directors have represented the Cooperative at these various shareholder meetings.

He recommended that the entire Board of Directors be authorized to act as the authorized representatives of the Cooperative, in its capacity as sole member or sole shareholder of each of these subsidiaries.

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

R02.10-11-16 RESOLVED, that the Basin Electric Board of Directors is hereby designated to participate in the 2016 annual shareholder meeting of Dakota Gasification Company and to exercise, on behalf of the Cooperative, its vote at said annual meeting, each such designated person to vote 1/11th of the interest of the Cooperative.

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

R03.10-11-16 RESOLVED, that the Basin Electric Board of Directors is hereby designated to participate in the 2016 annual shareholder meeting of Dakota Coal Company and to exercise, on behalf of the Cooperative, its vote at said annual meeting, each such designated person to vote 1/11th of the interest of the Cooperative.

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

R04.10-11-16 RESOLVED, that the Basin Electric Board of Directors is hereby designated to participate in the 2016 annual shareholder meeting of PrairieWinds ND 1, Inc. and to exercise, on behalf of the Cooperative, its vote at said annual meeting, each such designated person to vote 1/11th of the interest of the Cooperative.

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

R05.10-11-16 RESOLVED, that the Basin Electric Board of Directors is hereby designated to participate in the 2016 annual shareholder meeting of PrairieWinds SD 1, Inc. and to exercise, on behalf of the Cooperative, its vote at said annual meeting, each such designated person to vote 1/11th of the interest of the Cooperative.

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

R06.10-11-16 RESOLVED, that the Basin Electric Board of Directors is hereby designated to participate in the 2016 annual shareholder meeting of Basin Cooperative Services and to exercise, on behalf of the Cooperative, its vote at said annual meeting, each such designated person to vote 1/11th of the interest of the Cooperative.

Mr. Foss noted that Nemadji River Generating, LLC does not have an annual meeting.

C. Report on Oral Arguments on Clean Power Plan

Attorney Anine Lambert reported on the Clean Power Pan (**CPP**) oral arguments before the D.C. Circuit Court of Appeals on September 27th.

D. Executive Session

At 3:00 p.m., it was moved by Director Presser, seconded by Director McQuistion and carried to move into executive session to hear a report on LRS Best Available Retrofit Technology Settlement.

At 3:10 p.m., it was moved by Director Gilbert, seconded by Director Presser and carried that the Board arise from executive session.

8. Operations Report

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

He provided bus-bar costs for the coal-fired fleet, reviewed the equivalent forced-outage rate trends for the past 24-month period and reviewed the year-to-date running plant capacity factors for the coal units. September generation for the owned and operated Basin Electric fleet came in at 2,158,663 MW compared to the budget of 1,968,483 MW, which is 9.7% over budget for the month. Year-to-date generation is 2.8% below budget.

Integrated Test Center. Wyoming Governor Mead made the public announcement that the general construction work contract for the Integrated Test Center (**ITC**) was awarded to a local contractor, Hladky Construction of Gillette, Wyoming, for approximately $5.3 million. Mr. Jacobs reported that Amendment 1 to the ITC Agreement was to conduct a level 5 engineering estimate of splitting the large test center into two test bays and installing minimum gas recirculation lines. Amendment 2 modified the ITC publicity provision of the agreement. Amendment 3 calls for the installation of a minimum gas recirculation line to a single LTC bay in order to reduce the minimum gas flow from 12 MW to 5 MW of flue gas. This amendment will need to be approved by the state of Wyoming for an additional $810,000 to the original agreement.

The state of Wyoming announced the web site for technology providers to input their proposals. Proposals will be received through November 2016 and will be reviewed from December 2016 through February 2017.

Xprize announced last week that 47 proposals to use the ITC had been received from seven different countries. This number will be narrowed to 15 and after the first of the year, it will be narrowed to the five selected. Those five will receive $2.5 million. Tests start at the end of 2017, will run for two years and then the Xprize group will make an award of the remaining $7.5 million to the winner. Mr. Jacobs anticipated the whole process to take at least eight years.

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

Unit	Availability	Running Plant Capacity Factor(net)	Unit Rating	Comments
AVS #1	100%	96.4%	450 MW	
AVS #2	66%	93.5%	450 MW	Forced outage for broken HP seal oil line in reservoir; forced outage for low CT basin level; scheduled outage to repair delta PT failed alarm.
DFS	100%	102.15%	386 MW	
LRS #1	53%	55.69%	570 MW	
LRS #2	100%	80.32%	570 MW	
LRS #3	100%	80.84%	570 MW	
LOS #1	97%	88.58%	221 MW	
LOS #2	88%	88.27%	448 MW	Scheduled outage to repair RSH tube leak.

A. Distributed Generation Update

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 Generation Station (**PGS**) and Lonesome Creek Station (**LCS**)) were stable during the month. September generation at the distributed generation facilities was as follows:

Unit	Monthly Availability	Monthly Generation	Unit Rating	Comments
Culbertson CT	45.42%	3,967 MW	97 MW	Ran for load demand. Scheduled outage to change out variable bleed valve controls.
DCS	95.78%	39,206 MW	300 MW	Ran well for load demand. Started scheduled combustion turbine outage 10/1/16.
Groton #1	23.99%	284 MW	100 MW	Ran for load demand. Unit 1 struggled. Jacking oil system and somewhere, it was found that someone put on a coupling that's meant for conduit on 3500-psi oil system.

				Over time it finally failed and oil leaked out. Inside the exhaust collector area, the enclosure exhaust fan creates a draft and pulls oil mist over the engine and bearing area and insulation got soaked and then hot. Hard to get in this area. Took about two weeks to get inside, take out insulation, and replace with correct coupling. Don't know when it happened. BEPC current staff did not do this.
Groton #2	96.17%	7,362 MW	100 MW	
LCS #1	98.91%	19,368 MW	45 MW	Ran well. Lot of generation. Planning outages later this month to boroscope, inspect and perform package tuning.
LCS #2	100%	23,702 MW	45 MW	
LCS #3	100%	22,573 MW	45 MW	
PGS #1	97.58%	16,702 MW	45 MW	Ran well for the month.
PGS #2	99.53%	16,253 MW	45 MW	
PGS #3	99.93%	15,915 MW	45 MW	
SMS #1	100%	160 MW	60 MW	Ran 2.5 to 3 hours during the month. Prices were $27 but we received a make-whole payment from the market.
SMS #2	100%	139 MW	60 MW	
WDG	99.5%	0 MW	45 MW	Did not run.

Mr. Tschosik then presented photographs and discussed the CCT variable bleed valve and the DCS air-cooled condenser, the DCS combustion turbine fuel nozzle and assembly, transition pieces and the combustor liner and flow sleeve and the GGS jacking oil piping.

PrairieWinds ND (PWND). Blade repairs have been completed, annual maintenance is 78% complete and Southwest Power Pool (**SPP**) Regulation down testing was completed during the month. PWND passed deployment testing and is now on five-minute dispatch. On December 1, 2016, it will go into regulation to perform Regulation Down, which appears to have value in the SPP market. We wanted to test the PWND facility before making this change to PWSD.

The east-side peak occurred on September 1, 2016 at hour ending 1900. At that time, wind generation was as follows:

Wind Project	Load Factor during the Peak	Capacity Factor		Project Total
		Month	YTD	
Baldwin	94 MW	46%	43%	99 MW
Campbell County	92 MW	47%	47%	88 MW
Day County	69 MW	55%	49%	99 MW
Edgeley	17 MW	31%	29%	40 MW
Highmore	30 MW	41%	38%	40 MW
Iowa Wind	3 MW	36%	36%	45.1 MW
Other Projects (Chamberlain & Pipestone)	1 MW	18%	43%	3.4 MW
PWND	112 MW	43%	41%	123 MW
PWSD	108 MW	46%	43%	162 MW
Wilton	83 MW	43%	40%	99 MW
Total Monthly Wind Generation	609 MW	39%		800 MW maximum
Average Capacity Factor		41%	42%	

B. AVS Plant Update

AVS Plant Manager Chad Edwards reported that as of September 17, 2016, AVS employees had worked 222 days or 258,243.9 hours without a DART case. The total case incident rate is 1.99. He reviewed the safety incidents and Continuous Improvement inspections by month.

AVS September generation was 493,915 MWh, which is 88.34% of the budgeted generation of 559,110 MWh. Year-to-date station generation was 4,140,443 MWh compared to the budget of 4,459,090 MWh. He reviewed the AVS plant targets for heat rate, net generation, availability, forced outage rate, station service, number of starts, scrubber compliance and safety.

In August, AVS set an all-time station generation record of 636,981 net MWh which is impressive for a 30-year-old unit.

AVS Unit #2 began commercial operation in June of 1986. Its continuous run record was set in 1994 at 336 days, 18 hours and 12 minutes. There are currently 54 employees working at AVS that were employed at AVS during start-up.

Mr. Edwards reviewed budgeted and actual year-to-date operating expenses for fuel, maintenance and operations.

Current AVS projects include coal system upgrades for combustible dust, AVS combustion optimization, AVS simulator, mercury emissions control and remodel of the administration building. He then provided a list of the 2014 to 2016 capital project requests and the cost variations from budget to actual.

9. Risk Management Report

Manager of Commodity Risk Kerry Kaseman reported that the current average hedged price for on-peak east purchased power is $27.66/MW in 2016 and $28.23/MW in 2017.

The current hedged position for natural gas is $2.08 per dekatherm (**dkt**) for 2016, $3.05/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 $1.76/dkt and the average sale price at the time of injection is $1.33/dkt.

He reviewed the Ventura Forward Curve which, as of October 1, 2016, starts at $3.07/dkt for 2016 and 2017, decreases to $2.81/dkt for 2018, drops to $2.69/dkt for 2019, is $2.72/dkt in 2020 and is $2.82/dkt in 2021.

There were no September settled financial hedges for natural gas. The total Mark-to-Market (**MTM**) for natural gas was a loss of ($8.1 million) from $2.2 million last month.

He reviewed the current hedged price for west surplus sales, which for the peak is $26.87 in 2016 and $28.08 in 2017 and for the off-peak is $0.00/MW in 2016 and $22.42 in 2017.

He reviewed the Palo Verde On-Peak Forward Curve which, as of October 1, 2016, was $29.50/MW for 2016, $30.05/MW for 2017, $29.73/MW for 2018, $30.36/MW for 2019 and ended at $30.83/MW for 2020.

The September settled financial hedges for 45 MW of power resulted in a net loss of ($204,170).

He reviewed the MTM power gain of $1.3 million, which does not include the negative ($19.7 million) MTM 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 on-highway diesel price projections. The September settled financial hedges for diesel resulted in a gain of $14,169 on a 77,000-gallon diesel hedge. As of September 31, 2016, the diesel MTM was a gain of $302,000.

The aggregate settlement for all commodities for the month was ($190,001) and $248,707 year-to-date, which does not include the MTM gain/loss on premiums and ineffective hedges. He then reviewed the ($6.5 million) loss on MTM for all commodity hedges, liquidity position and credit exposure by Moody's Investor Service (**Moody's**) credit ratings.

10. Marketing & Asset Management Report

Manager of Marketing & Financial Analytics Valerie Weigel reported that record temperatures drove cooling demand in September. The September power burn is expected to average 30.5 billion cubic feet per day, marking the fourth consecutive record-setting month in a row. October gas demand from power generation is expected to exceed previous October highs given gas-fired generation replacing coal generation.

Average transacted load-zone purchases were $22.19 versus a budgeted price of $22.66. Average transacted sales price was $19.79 versus a budgeted price of $21.33. September had significant market congestion given the AVS-to-Charlie Creek transmission outage. This is expected to end in mid-October. Given congestion products, day-ahead congestion was completely covered and also allowed a profit margin of $1 million.

We are starting to see economic shutdowns. The George Neal Station was offered in economically by MidAmerican.

The peaking stations continued to run. Day-ahead prices for the peaking units in the Bakken averaged $10/MWh higher than the baseload units. In addition, congestion was high at the Miles City Tie and Montana load was primarily served through west-side power.

Generation sales prices and load purchase prices for September were very close to budget ranges with some variability by day.

Basin Electric held a short position the first half of September while AVS Unit #2 was offline and held a long position the second half of September when AVS Unit #2 was back online.

There was a $2.6 million favorable variance from budget on the West in September. The average transacted sales price was approximately $21.68 compared to the budget of $19.67. The West units were online all month. Power was primarily moved from west to east across the ties throughout the month. West-side prices are down considerably from last month. The average day-ahead on-peak prices are down $8.00/MWh from August.

There was a $600,000 favorable variance from budget in Midwest Independent System Operator (**MISO**) in September. The average transacted load zone purchases were $17.97 versus a budgeted price of $23.63. The averaged transacted sales price was $23.11 versus a budgeted price of $19.60.

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, 657,000 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 $26.7 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 million BTUs, 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 $96.8 million versus the $95.0 million notional value of the plan. If the hedge plan is not yet fully executed, the open volumes are tied to the current market prices.

11. Recess and Reconvention

At 4:45 p.m., President Peltier recessed the meeting until 8:00 a.m. October 12, 2016, at which time the meeting reconvened with President Peltier continuing to preside and Secretary Gary C. Drost continuing to keep the minutes.

12. Roll Call

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

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

Said persons being all of the Directors of the Cooperative. Also present were Chief Executive Officer & General Manager Paul M. Sukut, Assistant Secretary Mark D. Foss and Basin Electric staff members Lynn Beiswanger, Tracie Bettenhausen, Andy Buntrock, Eric Carufel, Kelly Cozby, Shawn Deisz, Tammy DeWitt, Mike Eggl, Elizabeth Erhardt, Matt Greek, Deb Haga, John Jacobs, Steve Johnson, Kerry Kaseman, Bryan Keller, Becky Kern, Janet Kubisiak, Tracy McBride, Gavin McCollam, Darla Miller, Deb Olafson, Diane Paul, Mike Paul, Curt Pearson, Shawna Piatz, Dave Raatz, R.D. Reimers, Ken Rutter, Susan Sorensen, Myron Steckler, Amanda Wangler and Michelle Wiedrich. Also present were DGC Vice President David J. Sauer, East River director Galen Grant, Corn Belt manager Ken Kuyper and Innovative Energy Alliance Co-Manager/CEO Don Franklund.

13. Human Resources Update

Senior Vice President-Human Resources Diane Paul provided an update on a matter with the Equal Employment Opportunity Commission.

A. Benefits

Director of Labor Relations & Benefits Deb Haga reported that Basin Electric will retain Blue Cross/Blue Shield (**BC/BS**) for medical and dental insurance coverage for 2017. Staff negotiated reduced medical plan administrative fees with a two-year rate guarantee, saving approx. $15,000 in 2017. In 2017, the cost for the prescription drug co-payment at local pharmacies will be the same. The current stop-loss coverage with BC/BS will be maintained. Dental plan administrative fees with BC/BS were also reduced with a two-year rate guarantee.

UNUM will be retained for life, Accidental Death and Dismemberment (**AD&D**) and long-term disability coverages. Commissions were eliminated, lower rates were locked-in for three years and there will be a two-cent increase in employees' cost for life insurance. Due to low utilization, the short-term disability plan will be eliminated. The rates for vision insurance were locked-in for four years with a minor plan change on eye exams. Total savings to the Cooperative are estimated to exceed $900,000 for 2017.

The overall cost increases to employees were minimal. Employees pay five to 12% of the medical premium based on their annual salary. Increased 2017 costs for medical insurance range from $2.86 to $17.88 per month. Premiums for life insurance will cost an additional two cents per $1000. Premiums remain unchanged for AD&D, dependent life and AD&D, dental and vision coverages.

Goals for 2018 benefits include a comprehensive review of all benefit plan offerings, consideration of alternate providers of dental insurance and a review of plan utilization for possible plan design modification.

B. Amendment #1 to Restatement of Basin Electric 401(k) Plan

Manager of Benefits Plans Shawna Piatz reported that Amendment #1 to the Restatement of the Basin Electric Power Cooperative 401(k) Plan (**Basin 401(k) Plan**), the Basin Electric Power Cooperative ND/SD Union 401(k) Plan (**ND/SD**

401(k) Plan) and the Basin Electric Power Cooperative WY/NE Union 401(k) Plan (**WY/NE 401(k) Plan**) would provide for automatic enrollment of Basin Electric employees into a 401(k) plan with the default election into the employees' appropriate target year retirement fund. She recommended approval of Amendment #1.

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

R07.10-11-16 WHEREAS, the Board of Directors has maintained the Basin 401(k) Plan, the ND/SD Union 401(k) Plan, and the WY/NE Union 401(k) Plan for the benefit of employees of Basin Electric Power Cooperative (as specified in those plans); and

NOW, THEREFORE, BE IT RESOLVED, that the Board of Directors hereby authorizes Amendment #1 to the Restatement of the Basin 401(k) Plan, ND/SD Union 401(k) Plan and WY/NE 401(k) Plan;

BE IT FURTHER RESOLVED, that the Board of Directors hereby authorizes the CEO & General Manager, or his delegate, to execute all necessary documents required for such amendments of those plans.

C. Adoption of Basin Electric's Health and Welfare Wrap Plan #580

Ms. Piatz reported that the Health and Welfare Wrap plan would reduce the quantity of required document filings and will protect Basin Electric against any legal reporting and disclosure requirements such as Employee Retirement Income Security Act and the Health Insurance Portability and Accountability Act. It will cover all health and welfare plans and will be effective retroactively to January 1, 2016. She recommended adoption of this plan.

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

R08.10-11-16 WHEREAS, Basin Electric Power Cooperative (**Basin Electric**) and its subsidiaries provide certain benefits to its employees, which under the Employee Retirement Income Security Act (**ERISA**) are considered employee welfare benefit plans;

WHEREAS, under ERISA, these plans have various legal requirements which Basin Electric and its subsidiaries are required to fulfill;

WHEREAS, Basin Electric desires to consolidate its various health and welfare benefit plans into a single plan for ERISA reporting and disclosure requirements; and

WHEREAS, it is Basin Electric's desire to allow its subsidiaries to participate in the plan.

NOW, THEREFORE, BE IT RESOLVED, that the Board of Directors hereby authorizes the adoption of Basin Electric's Health and Welfare Wrap Plan (Plan #580); and

BE IT FURTHER RESOLVED, that the Board of Directors hereby authorizes the CEO & General Manager, or his designee, to execute all necessary documents requir3ed for adoption of the plan.

D. Learning & Development

Director of Learning & Development/Safety Lynn Beiswanger reported on Basin Electric's apprenticeship agreement at LRS for mechanical maintenance in a partnership with Bismarck State College. LRS Mechanical Supervisor Brian Kahler will serve as an advisory member. He thanked the training committee and union that worked to make this happen.

Basin Electric Leaders Professional Development, a new comprehensive learning and development opportunity, will be implemented in January. Classes will be offered on a 12-month cycle utilizing the workforce plan so that we can grow our future leaders from within, thus meeting one of the cooperative's strategic objectives.

E. Building Cooperative Connections

Mr. Beiswanger reported that people and relationships are the foundation of Basin Electric's success, and our goal for the Building Cooperative Connections program is to strengthen those relationships with our members as *Building Cooperative Connections* provides participants with the opportunity to share information and learn about the different roles at Basin Electric and our member co-ops. Ultimately, this will lead to building connections, relationships and a better understanding that together we are one, with a same mission: to improve the quality of life of Rural Americans by providing safe, affordable, reliable electricity. This program helps emphasize the power of human connections and our commitment to the communities where we live, work and serve our members at the end of the line.

Director Thiessen had recommended we contact Jason Brothen, CEO/General Manager of Lower Yellowstone Rural Electric Cooperative (**Lower Yellowstone**), for the first exchange. On October 3rd and 4th, the Basin Electric participants attended a Lower Yellowstone all-employee meeting and shared each other's cooperative history along with shadowing the Lower Yellowstone various departments and crews. On October 10-12, the Lower Yellowstone participants attended the project meeting and then met briefly with each Basin Electric Senior Vice President, who explained what their department does for Basin Electric. On Tuesday, the group toured AVS and the AVS 345 kV control building and yard and attended a Telecommunications information session. They also had an opportunity to visit with the Transmission System Maintenance (**TSM**) linemen and look over the live-line tools used for their work.

F. Safety

Safety/Occupational Health Administrator Kelly Cozby reported that participation in the Headquarters Our Power, My Safety (**OPMS**) focus cards has grown steadily since its inception in December of 2014. Other recent activities include training for new Steering Team Members, a significant update to the Steering Team Charter and Planning Document and discussion and planning for Continuous Improvement Teams 4 and 5. The OPMS Steering Team will provide information for Facilities to present prior to employee participation in the survey. The survey will be paper, not electronic and will cover 20 safety culture indicators. She reviewed the OPMS survey schedule and noted that it will cover 2,400 employees at nine locations.

14. Cooperative Planning Report

A. PURPA Assignment

Vice President-Cooperative Planning Dave Raatz reported that by accepting the members' assignment of their Public Utility Regulatory Policy Act (**PURPA**) obligations, Basin Electric is simply offering to its members an opportunity to unload some of those responsibilities.

He presented a chart listing the Cooperative's Class A members that have been authorized by their boards of directors to assign their PURPA obligation to Basin Electric and those who have chosen not to do so. Tri-State has elected to maintain the PURPA obligations for its members. The members of Northwest Iowa Power Cooperative and Corn Belt have assigned their PURPA obligations to their G&T. Four of the Great River Energy (**GRE**)-Fixing members will maintain their PURPA obligations (Meeker Cooperative Light Association, Federated Rural Electric Association, Minnesota Valley Electric Cooperative, and Wright-Hennepin Cooperative Electric Association (**Wright-Hennepin**). One East River member, Dakota Energy Cooperative, changed its mind and decided not to assign its PURPA obligation.

Mr. Raatz noted that it's been a lot of work for staff that is dealing with the issues that come with PURPA in the *Prelude* litigation. He will provide an update and describe the required publication process at the Managers Advisory Committee (**MAC**) meeting next week. Mr. Raatz stated that, if public meetings are required following the public notice process, Basin Electric will assist the members in that process.

He noted that this will require a one-time filing with the Federal Energy Regulatory Commission (**FERC**) for approval. Although a member could later rescind its assignment, FERC approval would be required. While there is no guarantee that FERC will approve these assignments, we currently do not expect to have any major issues.

B. Loads at Risk

Mr. Raatz reported that the topic of loads at risk was raised again at the July 2016 MAC meeting, after which Basin Electric staff spoke individually with each Class A member about their concerns for loads they considered to be at risk.

He presented a chart showing the areas where the Class A members believe they have loads at risk. There has not been much economic analysis, but we came away with three major areas of member concern--market access, self-generation and economic viability -- and quantified the magnitude of the loads indicated to approximately 1,000 MW. An economics analysis of the loads that have self-generation as an option was subsequently performed. Basin Electric staff compared the distribution cooperatives average rate to some potential self-generation alternatives to determine if the economics possibly worked for them to go self-generation. Basin Electric staff also looked at the financial impact to Basin Electric's margin if 200 MW of load was lost. The financial impact reflects decreased member revenue, increased non-member revenue, decreased purchase power due to a change in resource development and decreased transmission wheeling. In 2020, the financial impact is $48 million negative impact to the margin and by 2026 it moves to $5 million negative impact to the margin.

This will be discussed with the MAC next week and they will be asked what they'd like Basin Electric staff to do. He noted that we don't need a major change in the rate structure to deal with this.

C. <u>Nemadji Trio Energy Center</u>

Mr. Raatz reviewed the Nemadji Trio Energy Center (**NTEC**) development timeline and noted that the Board authorized Basin Electric to enter into an agreement with Minnesota Power Company (**MN Power**) and Dairyland Power Cooperative (**Dairyland**) for up to 400 MW of a combined-cycle unit (which equals 42% of the project) in Wisconsin. That agreement provides that MN Power will be the project operator.

MN Power issued multiple RFPs (wind, solar, demand response, and co-gen) in July/Aug 2016, responses were due back in September 2016. MN Power received over 6,000 MW of wind proposals in response to their Request for Proposals (**RFP**) and will go to the Minnesota Public Utilities Commission (**MNPUC**) early in 2017. Basin Electric staff has conference calls with MN Power and Dairyland every few weeks. MN Power staff represented to the group that there were no surprises in the RFP responses and that they see value to a dispatchable resource.

While not specifically required in the MNPUC Order, MN Power is considering to reduce its share of the NTEC project from 316 MW to 166 MW (a 17% ownership interest) for at least 10-15 years. Under the drafted agreements, MN Power would continue to be the NTEC operator.

MN Power indicated they were having discussions with another party for 50 MW of the reduced amount and asked if Basin Electric would take the remaining 100 MW of the reduced amount. MN Power stated that it was vital and imperative that Basin Electric participate in order for the project to move forward.

Basin Electric could take the additional 100 MW via a power purchase agreement (**PPA**) from 2023 to 2033 as long as it can show a need and the Board approves it. Basin Electric offered to increase its long-term ownership from 316 MW to 350 MW. MN Power counter-offered 66 MW for 10 to 15 years with a put and call option at net book value. While this seemed possible at first, it has since been determined that the Basin Electric Indenture would prohibit a purchase subject to a call.

Another option is to increase Basin Electric's ownership to 350 MW and negotiate a 66 MW 10-year PPA. MN Power wants to cover its full cost, but it would be difficult for Basin Electric to offer that. MN Power's financing costs would be higher than the Cooperative's.

Mr. Raatz noted that there was no viable option to present today and that a great deal of negotiation must take place if this project is to move forward, even though it is an economically viable project. The ultimate question is: Does Basin Electric want to stay involved in this project if MN Power, as a small minority owner, is project operator? This question generated a great deal of discussion, with many directors indicating that MN Power operation of the project as a small minority owner was a deal-breaker. Mr. Raatz noted that we have another month or two in which to make the decision.

15. North Dakota Statewide Visit

Director Thiessen introduced Josh Kramer, Executive Vice President & General Manager of the North Dakota Association of Rural Electric Cooperatives (**NDAREC**). Mr. Kramer spoke of his background, the work performed by NDAREC and the strong working relationship between NDAREC and Basin Electric.

16. Cooperative Planning Report, continued

A. Minnkota Power Cooperative

Mr. Raatz reported that the updated timeline shows the economic analysis has slipped to December of 2016, calls for a decision on direction in January 2017, potential agreement execution in the spring of 2017 and combined operations in the spring of 2018, although shared services could perhaps start sooner. The term sheet does not constitute a commitment but describes in reasonable detail fundamental details and structural components of a final arrangement. The wholesale power contract term would be June 1, 2018 through December 2075 and would provide that Minnkota and its membership purchase their power supply above the Western Area Power Administration (**Western**) allocation from Basin Electric and Minnkota and its members would assign their PURPA obligations to Basin Electric.

With respect to contract resources: (1) Basin Electric would purchase the capacity, power and energy associated with contract resources from Minnkota pursuant to power purchase agreements between Basin Electric and Minnkota, at Minnkota's cost; (2) Minnkota would continue to administer the contracts pertaining to contract resources, however, all decisions relating to all aspects of extension, termination, modifications, amendments, elections and other such matters would be subject to the approval of Basin Electric; and (3) under no circumstances would Minnkota enter into any new arrangements with respect to contract resources without the approval of Basin Electric.

With respect to owned resources: (1) Basin Electric would purchase the capacity, power and energy associated with owned resources (Milton R. Young Station also known as the Square Butte Facility) from Minnkota pursuant to power purchase agreements between Basin Electric and Minnkota, at Minnkota's cost; (2) it is further intended that administrative costs not specifically addressed in the RUS Form 12's would be negotiated; and (3) Basin Electric would have the right to schedule/dispatch Minnkota's share of the owned resources.

With respect to operations approval rights and administration: (1) Minnkota would keep Basin Electric informed of significant issues and decisions with respect to generating resources; (2) Minnkota and Basin Electric would establish an operating committee to review operational decisions, capital expenditures and budgets; (3) Minnkota would retain authority to make operational decisions and determine capital expenditures consistent with prudent utility practice; and (4) PPAs between Minnkota and Basin Electric would identify what level of capital, operational or retirement expense commitment require Basin Electric approval.

Following the October Board meeting, the parties are having additional discussions on item 4, however.

Special conditions include: (1) If the parties mutually agree to dismantle owned resources, Basin Electric would reimburse Minnkota for asset retirement costs and environmental liabilities related to such facility; and (2) Basin Electric and Minnkota staff would define additional conditions and provisions that will be required in the final agreements.

B. North Dakota Generation Company Discussion

Mr. Raatz reported on a meeting among staff from GRE, Minnkota and Basin Electric to discuss the pros and cons of working together more closely to maximize the hourly revenue potential of their North Dakota coal generation assets through a North Dakota generation cooperative (**ND GenCo**) owned by the three cooperatives.

The overall mission of the effort would be to explore whether NDGenCo would lower costs and risks while enabling participant-specific policy objectives in ways that are easier or less costly than pursuing the same objectives individually. The parties may consider expanding the scope to additional coal assets in other states.

The objectives would be to maximize the economic value and reduce potential losses of the coal fleet by facilitating the pursuit of value-increasing activities not readily available to the individual owners; diversify/pool the operational, regulatory and market risks in larger, less concentrated asset portfolio and support individual policy objectives and resource needs of the participants.

The principles would be to contribute assets based on their fair market value, cooperative governance, consider the economic impacts of decisions on individual parties, maintain a ratio of SPP and MISO resource adequacy capacity, create an organization that is autonomous and the NDGenCo would have a duty to operate assets based on sound business and prudent utility practices.

The obvious first step, given these objectives and principles, is each cooperative must determine whether the creation of a NDGenCo is conceptually an option. Staff believes that it would not be in Basin Electric's best interest to turn over its North Dakota coal generation and coal mine assets to an independent NDGenCo. The Board of Directors agreed with that assessment.

C. Contract Extension Credit

Mr. Raatz reviewed the depreciation schedule for the Cooperative's generation facilities before and after the depreciable life extensions. He noted that the schedule assumed no early facility retirements and no new facilities.

The 2016 contract extension credit was $37 million. The 2017 extension credit is $40 million. Currently there is a crossover point in 2045 where depreciation is actually higher as a result of the depreciation extension. Tri-State, Minnesota Valley and Wright-Hennepin contracts all expire in 2050 and all others expire in 2075. As we were working through some of these issues, Tri-State has asked for more information.

Staff is developing the language to include in the 2018 Rate Schedule A which will define depreciation periods for the 2050 contracts as well as the calculation of the contract extension credit. This will be presented to the Board for approval next summer. This is one of the last outstanding issues to try to put this issue with Tri-State to bed.

D. Transmission Service Mitigation

Mr. Raatz reported that Basin Electric has some loads that require SPP transmission service, some loads that require MISO transmission service and some loads that require both. The Blue Flint Ethanol Plant is an example of requiring both. The primary delivery point is from MISO's Underwood Substation. If there is a problem with that delivery point, the alternate delivery point is SPP's Washburn Substation. In order to keep reliable transmission service, transmission capability is reserved from both MISO and SPP (at Basin Electric's expense to the edge of the high-voltage transmission system). We could potentially avoid that pancaked wheeling cost by having two SPP delivery points, which would eliminate $360,000 per year for the MISO transmission path. In this example, this would require a $3 million investment in a new transmission line and modification of a substation. Basin Electric has historically not made this type of investment and this is an area where there is serious potential for unanticipated consequences. Basin Electric staff will be visiting on this concept at the upcoming MAC meeting.

E. Managers Advisory Committee Meeting

Topics of discussion for the October MAC meeting include a financial and austerity update, member load growth forecast, loads at risk, West regional transmission organization development, new member discussion update, PURPA assignment, member question discussion, Basin Electric/DGC market update and long-term resource planning.

F. Membership Transmission Lease Agreements

Mr. Raatz reported that under the MISO tariff, if you are a transmission owner, there is a mechanism for you to submit your annual transmission revenue requirement and transmission customers pay for it through the tariff. The transmission customers have the same option via a facility credit. Basin Electric is the transmission customer in MISO for the member load in MISO. How do we get those dollars for the benefit of the membership with facilities in MISO that qualify for inclusion in the tariff? If Basin Electric had a lease agreement for those facilities and the member submits that cost, Basin Electric pays the lease and ultimately it balances out. Basin Electric submits those dollars to MISO through the facility credit process and the dollars come back down. We have identified members that have MISO qualifying facilities, the annual transmission revenue requirements (**ATRR**) associated with those facilities is slightly over $3.1 million per year. Nearly all facilities would be includable in the Montana-Dakota Utilities Co. and Otter Tail Power Company zones of the MISO transmission tariff.

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

R09.10-11-16 BE IT RESOLVED, that the CEO & General Manager, or his designee, is authorized to execute Member Lease Agreements and other documents to acquire MISO Facility Credits to offset Member MISO Transmission qualifying facility costs.

G. Wind Purchase

Director of Utility Planning Becky Kern reviewed the power supply planning timeline with the objective of identifying the least-cost long-term power supply for the membership through market purchases, natural gas peaking, natural gas combined-cycle and wind using a view of the future as opposed to a view of the last six to 12 months. The long-term analysis includes consideration of natural gas prices, wind development, cost of emissions, fuel-cost impacts, solar generation and carbon capture, but does not factor in any CPP rules. She reviewed the prior

CPP Analysis performed in late 2015, the analysis which showed the following nameplate capacity portfolios:

	2016	2025 based on 2016-2025 Financial Forecast:	2025 based on potential CPP:
Coal:	50%	39%	18%
Gas/Oil/Diesel:	22%	36%	43%
Wind:	21%	19%	34%
Other Renewable:	6%	5%	4%
Nuclear:	1%	1%	1%

The 2025 portfolio under the CPP could require an additional 1600 MW of wind above what is currently contracted and included in the 2016 and 2025 non-CPP case.

She reviewed the phase-out of the production tax credit and the resulting 2016 contract execution value, She walked through the specific information about the final wind proposal (200 MW at Crocker, SD, 200 MW at Burke, ND and 300 MW at Burke, ND) and the percent reduction in the purchase price that was achieved through negotiations over the last couple months. She then provided a cost comparison of the two wind proposals.

Ms. Kern provided a project value comparison, (not including any costs/benefits for the CPP or a carbon constrained future), for each project. On October 3, 2016, Canada unveiled a plan for a national carbon tax of $50 (Canadian) per metric ton by 2022. She then reviewed that there may be an opportunity to market some magnitude of wind to a third party.

Vice President & Treasurer Susan Sorensen reviewed the recommendation of the Risk Management Steering Committee: (a) to pursue a wind power purchase agreement with the following terms: 200 MW nameplate capability starting December 31, 2019; pricing starting at $18.50 (or better) per MWh and escalated 1.5% per year; contract terms to include non-compensable curtailment of at least 10,000 MWh per year, with bankability preferred; and financial security in a form acceptable to Basin Electric should be sought; and (b) Cooperative Planning should seek to off-lay between 20 MW and 30 MW to a third party.

Ms. Kern recommended the CEO & General Manager be authorized to execute a wind power purchase agreement for 200 MW as outlined above under terms and acceptable conditions to the CEO & General Manager.

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

R10.10-11-16 RESOLVED, that the CEO & General Manager, or his designee, is hereby authorized to execute a wind power purchase agreement for 200 MW with an option to increase 100 MW to 300 MW as outlined above under terms and conditions acceptable to the CEO & General Manager.

17. Recess and Reconvention

At 12:30 p.m., President Peltier recessed the meeting until 1:30 p.m., at which time the meeting reconvened with President Peltier continuing to preside and Secretary Gary C. Drost continuing to keep the minutes.

18. 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 Chris Bauer, Tracie Bettenhausen, Eric Carufel, Ted Cash, Tom Christensen, Shawn Deisz, Tammy DeWitt, Mike Eggl, Pius Fischer, Matt Greek, John Jacobs, Dan Job, Steve Johnson, Bryan Keller, Becky Kern, Janet Kubisiak, Tom Leingang, Shawnel Maxwell, Gavin McCollam, Darla Miller, Robert Nasset, Dale Niezwaag, Deb Olafson, Mike Paul, Dave Raatz, Jean Schafer, Marcie Schorsch, Myron Steckler, Chris VandeVenter, Michelle Wiedrich and Mike Zimmerman. Also present was East River director Galen Grant.

19. Engineering & Construction Report

A. Project Funding Chart

Senior Vice President-Engineering & Construction Matt Greek reported that three Basin Electric contracts totaling $6.9 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. Headquarters Building Expansion Project Update

Structural Engineering Supervisor Chris Bauer reported that the Board approved the east blunt-front addition project in May 2015, which is complete. The Board approved the west addition project, including the east and west parking lots, in August 2015. The west addition scope includes design and construction of a 91,000 square foot addition and associated site work. The warehouse/shop project was also approved in August 2015 and the scope includes design and construction of a 4,800 square foot building and associated site work. He presented a diagram of the site layout.

Northwest Contracting has a full-time site safety representative on site. All workers go through a site safety orientation upon arrival to the site. Daily safety talks and weekly safety meetings are held with all contractors. Headquarters Safety meets with the contractor on a regular basis. There have been two incidents to date: one a Basin Electric property damage incident and one contractor equipment damage incident.

The warehouse/shop building shell and interior walls are complete. Trim-out of mechanical and electric work is ongoing. Painting and other interior finish work is ongoing. Associated site work remains. The anticipated occupancy date is November 2016. He presented photographs of the warehouse/shop.

The west addition foundation work is nearly complete. Precast floor structure, roof structure and wall panel erection is 70% complete. Third floor mechanical and electrical rough-ins are ongoing. Large distribution HVAC ductwork is installed on third floor. All design work and drawings for department and office layouts for the new addition are in the final review and approval stage. He presented photographs of the progress on the west addition. Occupancy is scheduled to begin in September 2017.

The next major milestones on the west addition are completion of the precast concrete and steel erection in November. It is anticipated that the west addition, including roofing and exterior windows, will be enclosed in early 2017. He then reviewed the overall schedule and budget. The projected final cost is $36,062,330 and the approved amount is $42,419,682.

C. History and Approach to Capital Project Management

Mr. Greek reported that Basin Electric has managed a number of projects, big and small, complex and straightforward, in its history. Included in the Engineering & Construction report this month are eight major projects with a total budget exceeding $1.6 billion, four projects each with a budget greater than $10 million, 24 projects each with a budget between $1 million and $10 million, five projects being closed out and 220 active Requests for Engineering Services.

He noted it is helpful to think in terms of a risk continuum. For example, active management assumes outcome risk and ownership of outcome while passive management assigns that risk and ownership of outcomes to another party or parties at a price. Basin Electric and DGC tend to prefer active management approaches which maximize staff influence and control. Most or all material project risks are held by Basin Electric or selectively assigned (such as performance warranties or guaranties). This approach typically reduces the fees associated with assigning risk and gives Basin Electric/DGC full sway on questions of value (such as degree/return of capital spend and benefits of operability/maintainability).

20. Transmission Report

Vice President of TSM Bryan Keller reported that as of September 30, 2016, the TSM Division employees have worked 148 days without a DART incident. There were no personal injuries or vehicle incidents in September.

TSM energized both transformers at Patent Gate, finished commissioning and energized the Patent Gate-to-Kummer Ridge section and tested the Kummer Ridge equipment. The crews energized the 230/115 kV transformer at Roundup. He noted that the original AVS-to-Charlie Creek line was built in 1984 and the equipment is also that vintage. Staff is in the process of removing those and replacing protective relays with microprocessor relays.

A. Amendment to Capital Project 02779, Blaisdell 230/115 kV Spare Transformer T2 Addition Project

Mr. Keller reported that this amendment provides for the installation of additional relaying and monitoring circuits to permit the energized transformer to be stored at normal voltage. The transformer will be tied into the SCADA system, so once it is energized, it can be remotely monitored for moisture, abnormal gases and temperatures, among other things. It will also provide confidence that the transformer won't have any electrical or mechanical problems, which cannot be known if the unit is not stored in an energized state. The estimated cost of this amendment is $470,000. The transformer was only energized at the HICO test facility in South Korea during factory acceptance testing. He presented a photograph of the Blaisdell 230/115 kV Transformer T2 and recommended approval of the amendment.

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

R11.10-11-16 RESOLVED, that the amendment to Capital Project 02779, Blaisdell 230/115 kV Spare Transformer T2 as presented to this meeting of the Board of Directors with an estimated cost of $470,000 is hereby approved; and

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

B. Teckla Interconnection Agreement with Black Hills and PRECorp

Manager of Transmission Rates Tom Christensen reported that Black Hills Power & Light Association (**Black Hills**) is interconnecting its 230 kV line from Osage into the Teckla Substation. This Interconnection Agreement among Powder River Energy Corporation (**PRECorp**), Black Hills and Basin Electric details the terms and conditions of that interconnection. He noted that the Teckla Substation Addition was authorized by the Basin Electric Board of Directors in February 2014 at a cost of $2 million and a contract term of 35 years. Basin Electric is responsible for construction and PRECorp has ownership and cost responsibility. PRECorp is making the ATRR filing. This agreement grants no contract path or capacity rights on any Party's transmission system.

He recommended authorization to execute the Teckla Interconnection Agreement.

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

R12.10-11-16 RESOLVED, that the CEO & General Manager, or his designee, be authorized to enter into the Teckla Interconnection Agreement with Powder River Energy Corporation and Black Hills Power & Light Association on terms and conditions he finds to be in the best interest of the Cooperative.

C. Settlement Authorization FERC Docket No. ER15-1775

Mr. Christensen reported that the parties that intervened in Basin Electric's FERC SPP ATRR filing have agreed in principle to a settlement. The settlement package calls for 9.6% Base Return on Equity (**ROE**), 36.3% equity ratio and a 1.95% composite depreciation rate. An ROE/Equity moratorium would extend through October 1, 2019. There would be a requirement for Basin Electric to refile no later than January 1, 2024. The settling parties are SPP, Basin Electric, Corn Belt, East River, Heartland Consumers Power District, Kansas Corporation Commission, Missouri Public Service Commission, Missouri River Energy Services, Northwest Iowa Power Cooperative, Northwestern Energy, Western and Xcel Energy.

Mr. Christensen recommended the Board authorize the acceptance of the Unopposed Offer of Settlement and Settlement Agreement associated with FERC Docket No. ER15-1775-000 as presented.

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

R13.10-11-16 BE IT RESOLVED, that Basin Electric Power Cooperative is hereby authorized to accept the Unopposed Offer of Settlement and Settlement Agreement associated with FERC Docket No. ER15-1775-000 as presented; and

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

D. Southwest Minot-to-Berthold 115 kV Line Reconductor Additional Line Upgrades

Gavin McCollam introduced Senior Civil Engineer Robert Nasset, who reported that Basin Electric previously received a Notice to Construct from the SPP (SPP-NTC-200388) to install larger conductors on the southwest Minot to Berthold 115kV line. The project scope calls for replacement of the existing conductors and hardware, 15 structure replacements, existing structure modifications and right-of-way access. He noted that this is part of the original Logan-to-Kenmare line build in 1978. The whole line consists of 90 structures.

The project scope of the additional line upgrades calls for replacing the existing shield wires and shield wire angles, seven new full-tension dead-end structures and right-of-way access.

He presented photographs and discussed shield-wire icing, modification of the existing structures and new storm structures. The Class 2 budget estimate for the reconductoring is $3,544,000. The Class 2 budget estimate for the additional line upgrades is $2,884,000. The estimated project schedule calls for engineering from August through December of 2016, procurement from November 2016 through May 2017 and construction from February through December of 2017. He recommended approval to proceed with the project at a cost of $3,544,000.

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

R14.10-11-16 BE IT RESOLVED, that the Southwest Minot-to-Berthold Reconductoring Project presented to this meeting of the Board of Directors with an estimated project cost of $3,544,000 be approved; and

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

E. Southwest Minot-to-Berthold 115 kV Line Shield Wire Replacement/Storm Structure Installation Project

Mr. Nasset reported that the existing shield wires on the line require replacement. The line also needs storm structures to be installed to prevent cascading structure failures. He recommended Board authorization to proceed with the project at a cost of $2,884,000.

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

R15.10-11-16 RESOLVED, that the SW Minot-to-Berthold Additional Line Upgrades project presented to this meeting of the Board of Directors with an estimated project cost of $2,884,000 be approved; and

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

Mountain West Transmission Group. Mr. Christensen reported that this effort continues to gain momentum. Mountain West Transmission Group (**MWTG**) issued a Request for Information to SPP, MISO, PJM Interconnection LLP and California Independent System Operator (**CAISO**). CAISO was eliminated on August 24. DC Tie proposals and questions were sent to SPP and MISO on August 30. Staff is pursuing additional market analysis. An in-person meeting to share initial individual MWTG participant rankings was held on September 8. Additional meetings to discuss the Brattle Group Study Results were held on October 4-6. The next meeting is October 20.

21. Communications & Administration Report

Senior Vice President--Communications & Administration Mike Eggl reported on meetings held during the Fall Fly-in to Washington DC. He also discussed the National Rural Electric Cooperative Association Region 5&6 meeting. Dale Niezwaag discussed the September 19-20 North Dakota legislators' trip to Houston, Texas to tour an Allam Cycle facility pilot plant, a Danbury Oil field where they're injecting carbon dioxide for tertiary oil recovery and Petra Noble Plant (backend capture on existing plants), which has commenced construction. Staff is considering a similar tour next spring with the new North Dakota governor and staff.

He reviewed the Board Policy review schedule and noted that Board Policy 01, Renewable Resource Obligations had been presented for review in September and action would be requested this month. The review team had no suggested revisions. Hearing no comments, the policy was reaffirmed.

Board Policy 02, Fiscal Policy (et al.) was then presented to the Board for their review. Revisions, if any, will be presented in December and approval or reaffirmation will be requested.

He then reported on the annual meeting, Norsk Hostfest and promotion of Co-op Month.

Legislative Representative Chris VandeVenter provided an update on various election polls.

22. Financial Services Report

Senior Vice President & Chief Financial Officer Steve Johnson discussed National Rural Utilities Cooperative Finance Cooperative financial results, financial/market update and the end-of-year projections.

As Directors Baker and Presser have conflicts with the December rating agency visits and bank meetings, so Directors Peltier and Pearson will attend along with Paul Sukut, Mr. Johnson and Susan Sorensen. Visits to the rating agencies will be increased to twice a year. This will be a short visit with updated financials and to review the benefits of the 7-mill rate increase and austerity measures.

On a consolidated basis, the estimated year-to-date margin estimate is finally positive at $11.9 million and the estimated year-end margin is $71.1 million, which includes recognition of the remainder of the deferred revenue.

A. Accounting Report

Senior Accounting Analyst Darla Miller reported that the September 2016 Statement of Operations reflects an estimated net margin of $39.5 million compared to the budgeted net margin of $7.8 million for a favorable variance of $31.7 million. The net margin last month was $32.2 million and the margin for September 2015 was $1.5 million.

September member sales were approximately $0.2 million higher than budget, which includes the August actualization of $0.6 million. September sales are estimated to be $0.4 million less than originally forecasted, due to weather. The lower generation was offset by positive pricing variances. Year-to-date member sales are approximately $36,000 below budget.

September surplus sales were approximately $1.6 million higher than budget, which includes the August actualization of $0.5 million. September sales are estimated to be $1.1 million more than originally forecasted. Surplus sales were higher due to higher generation offset by lower prices than anticipated.

Ms. Miller then reviewed operations expenses, maintenance expenses, year-to-date consolidated net income/loss, changes to the balance sheet and month-end cash. For the year-to-date, the Basin Electric family has consolidated earnings of $11,907,668.

Basin Electric's September equity-to-asset ratio was 17.9% compared to 17.5% in August.

The September equity-to-capitalization ratio using the Moody's methodology (both without the consolidation entry for The Coteau Properties Company) was 21.4% compared to 20.9% in August.

The September equity-to-capitalization ratio based on indenture requirements for patronage distribution was 21.3% compared to 20.6% in August.

23. Ratification of Western Fuels Association & Subsidiary Annual Meeting Delegate

Mr. Foss reported that the forms for naming delegates and alternates to the 2016 WFA and subsidiary annual meetings were not received this year. As Joe Leingang attended these annual meetings on behalf of Basin Electric, Mr. Foss recommended that the Board ratify Joe Leingang as delegate to the WFA and subsidiary annual meetings. It was moved by Director Gilbert that Joe Leingang be ratified as Basin Electric's delegate to the 2016 WFA and subsidiary annual meetings. The motion was seconded by Director Drost and carried.

24. Minnesota Statewide - 2017 Membership Meetings - Delegate & Alternates

Mr. Peltier noted that a delegate and alternate are needed to represent the Cooperative at the 2017 Minnesota Statewide meetings. For 2016, Director Drost served as the delegate and Director Peltier as the alternate. After discussion, it was moved by Director Thiessen and seconded by Director McQuistion that Directors Peltier and Drost serve as voting delegate and alternate, respectively. The motion carried.

25. Directors' Reports

Director Baker reported that PRECorp's chief operating officer is taking the General Manager position with Oregon Trail Electric Cooperative and will be leaving at the end of October.

Director Rohrer reported on the Montana Statewide meeting and thanked Messrs. Sukut and Eggl for attending.

Director Presser expressed his appreciation to Director Thiessen for allowing him to attend the NDAREC meeting.

Director Thiessen reported on positive feedback received following Mr. Sukut's speech at the NDAREC meeting. He reported that the "Building Cooperative Connections" program had been very well received at Lower Yellowstone.

Director Gilbert noted that the Directors would be in Bismarck for the November Board and annual membership meetings during the election, so he encouraged them to vote via absentee ballot before traveling to Bismarck.

Director Brekel reported that Chris VandeVenter has been attending the Mid-West Electric Consumers Association (**MECA**) policy review meetings for a long time and he thanked Basin Electric for allowing Mr. VandeVenter to participate.

Director Drost reported that MECA Executive Director Bill Drummond had recommended that the resolutions committee thoroughly review the resolutions in an attempt to combine and improve them. Director Drost noted that it had been a long process, but he recommended that the Basin Electric Resolutions Committee consider doing the same. He suggested the Resolutions Committee select the top 10 resolutions to take to the legislators. He noted that it had been a tremendous meeting, especially the resolutions. Director Brekel agreed.

26. Date and Time of Next Board Meeting

President Peltier noted that additional time is needed at each of the meetings next month for budget presentations. The next regularly scheduled meeting of the Board of Directors will take place starting Sunday, November 6, 2016 for the DGC, Dakota Coal Company and Montana Limestone Company board meetings. Schedules will be emailed as usual.

He also noted that the Directors will be staying at the Ramkota Inn next month because it is more convenient for the annual meeting. The Basin Electric annual meeting will take place November 8-9, 2016, at the Bismarck Event Center, 315 South Fifth Street, Bismarck, North Dakota.

27. Adjournment

President Peltier adjourned the meeting at 4:45 p.m.

Gary C. Drost
Secretary-Treasurer