Approved April 12, 2016

Basin Electric Power Cooperative
Bismarck, North Dakota

Minutes of the Regular Meeting of the Board of Directors
March 15-17, 2016

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The Regular Meeting of the Board of Directors of Basin Electric Power Cooperative (the **Cooperative** or **Basin Electric**) was held at the headquarters building, Bismarck, North Dakota, beginning on March 15, 2016 at 1:00 p.m. CDT.

1. Call to Order

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

2. Roll Call

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

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

Said persons being all of the Directors of the Cooperative. Also present were Chief Executive Officer & General Manager Paul M. Sukut, Assistant Secretary Mark D. Foss and Basin Electric staff members Tracie Bettenhausen, Dean Bray, Eric Carufel, Shawn Deisz, Tammy DeWitt, Ken Dolan, Mike Eggl, Matt Greek, John Jacobs, Steve Johnson, Becky Kern, Jon Klein, Darla Miller, Deb Olafson, Dave Raatz, R.D. Reimers, Mike Risan, Ken Rutter, Dain Sullivan, Justin Weichel, Cheri Wenzel and Michelle Wiedrich. Also present were Dakota Gasification Company (**DGC**) Vice President David J. Sauer, DGC director Alan Klein, East River Electric Power Cooperative (**East River**) director Rick Koupal and Deloitte and Touche LLP representatives Adam Krasnoff and Judi Dockendorf.

3. Recess for Board Audit Committee Meeting; Reconvention

At 1:00 p.m., President Peltier recessed the meeting to hold the Board Audit Committee meeting. He reconvened the Board of Directors meeting at 3:00 p.m.

4. Approval of the Agenda

The Directors considered the agenda for the conduct of the business of the meeting. Director Drost requested "Board Cost-Cutting Measures" be added to the agenda. After an opportunity for the addition and deletion of items, it was moved by Director Baker, seconded by Director Drost and carried that the agenda be approved as revised.

5. Approval of the Minutes

The minutes of the February 9-10, 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 McQuistion and carried that the minutes be approved as presented.

6. General Manager's Report

General Manager Sukut reported that the results of a poll concerning public attitudes regarding cooperatives was presented at the North Dakota Statewide meeting last week. He said the results were very positive.

A. Western Fuels Update

Director Paul Baker reported that the Western Fuels Association board of directors met at the end of February. It was an uneventful meeting. Wyoming Governor Mead has signed off on using $2.45 million of abandoned mine funding for the reroute of Highway 59, Campbell County road. This should save the Cooperative about $6 million.

7. Cooperative Planning Report

A. Tri-State Contract Discussion.

Dave Raatz, Vice President of Cooperative Planning, reviewed the timeline of the discussions concerning extending the Cooperative's contract with Tri-State Generation and Transmission Association, Inc. (**Tri-State**).

Mr. Raatz started with a PowerPoint presentation he had given to the Managers Advisory Committee (**MAC**) on June 26, 2012 regarding transmission policy contingent upon Basin Electric joining a regional transmission organization (**RTO**). This discussion was continued at the Basin Electric October 12, 2012 board meeting. The outline of the proposed transmission policy stated that if Basin Electric is the all-supplemental requirements supplier, Basin Electric would be responsible for all high-voltage delivery associated with power supply obligation. This would require a change in the Basin Electric point of delivery under the all-requirements contracts. This was also the first time the possibility of member-owned transmission/distribution facilities being included in the RTO was discussed.

By the June 24, 2013 MAC meeting, the transmission service policy option was pretty solid. Again, it would only apply to all-requirements contracts. Fixed contract rate of delivery (**CROD**) contracts with a defined hourly pattern with specific delivery points would be excluded. Typically you pay a Federal Energy Regulatory Commission (FE**RC**) pro forma tariff for the entire load. For all-requirements members, Basin Electric would be the contractual network customer for all FERC pro forma transmission service. This was a major undertaking on Basin Electric's part, as we would need to hedge congestion within an RTO. We knew we would need to modify the delivery points under the all-requirements power contracts. Basin Electric would be financially responsible for all FERC pro forma transmission service assessments for these all-requirement contracts and would bill the member for any incurred costs associated with the delivery of federal power. There would be no change to Basin Electric's fixed CROD obligations.

Towards the fall of 2013, we signed a Memorandum of Understanding (**MOU**) with the Southwest Power Pool (**SPP**) to work out the details of potential RTO membership.

Ultimately, the Cooperative worked through this and a commitment was made to join SPP. There were a lot of discussions and many membership meetings. We took member personnel to meet with SPP in Little Rock, Arkansas, and continued discussions trying to figure out how the pieces fit together. By July 2014, staff presented and received two board authorizations: (1) to join SPP; and (2) to work with the all-supplemental requirements members to change existing delivery points related to each member served in the footprint of a contiguous FERC pro forma, open-access transmission tariff. The resolution went on to direct staff to work with the all-supplemental requirements members to amend their wholesale power supply agreements to identify the new points of delivery and require that Basin Electric reserve transmission service necessary to implement the new transmission policy. This was the blueprint for how the Cooperative moved forward.

A timeline was laid out for the process and communicated to the members in an August 25, 2014 letter. In the March 2015 through May 2015 timeframe, staff would try to have all draft amendments to the wholesale power agreements put together with the goal of executing them by June 2015, sent to RUS in July 2015 with an effective date of January 1, 2016.

By October 2014, staff initiated discussions regarding Dry Fork Station (**DFS**) and if we wanted to extend the depreciable life of that facility. In addition, as we began building new generation facilities, their depreciable lives would extend beyond 2050. We also asked ourselves, what happens if we extend the depreciable lives of the other coal plants by 60 years and what happens if we start to extend the depreciable lives of the gas peaking plants to 50 years. That would move a lot more facility lives past the year 2050. It was at this point that we started talking about extending the term of the wholesale power contracts to 2075 (in addition to changing the delivery points).

By the January 2015 board meeting, staff outlined how the Cooperative would implement the transmission policy. Drafting of the contract extensions would begin in March with hopes of sending the amendments to the Rural Utilities Service for approval by the end of July 2015.

By February 2015, staff had come up with a game plan. Given the volume of the amendments, the Cooperative Planning and legal staffs informed the Board and membership we would break the amendments into three buckets. We would first work on the amendments that only required a change to the delivery points. Next we would work on the amendments with resource adder and new delivery points, and last, we would work on the Tri-State amendment given that Tri-State has members both east and west of the electrical separation and has both an all-requirements contract and a fixed-CROD contract.

Tri-State called and staff met with them on April 29, 2015. At the meeting, we confirmed contractual structure and confirmed that the Cooperative would cover SPP transmission assessments for Nebraska. Tri-State staff noted that a contract term extension was unlikely. Tri-State also stated that they would like to renegotiate west-side delivery details and to discuss conversion of Fixed CROD rate to base rate.

The week of the July 2015 board meeting, staff provided draft contracts to Tri-State. We got into some discussions associated with certain Great River Energy (**GRE**)-fixing members in the same time period. As a result of the GRE-fixing members' discussion, the board set the requirement that if a member did not sign a 2075 contract extension by January 1, 2016, the member would not get a contract extension credit.

Tri-State CEO Mike McInnes visited with the Basin Electric board in December, 2015. Major points were extension of the contract to 2075, coal plant depreciation schedule and the rate charged under the contracts expiring in 2050.

Tri-State is paying its power bills under protest.

Meetings with Tri-State to discuss their wholesale power contracts with the Cooperative have been scheduled for March 28 and April 19.

8. Executive Session

At 3:55 p.m., the Board retired into executive session to discuss the Tri-State contracts, the Laramie River Station (**LRS**) Best Available Retrofit Technology settlement, the Clean Power Plan (**CPP**), the legal report and the Energy Ventures Analysis CPP study. Director Brekel recused himself from the executive session during the Tri-State discussions. At 5:51 p.m., it was moved by Director Rohrer, seconded by Director Gilbert and carried that the board arise from executive session.

9. Recess and Reconvention

At 5:51 p.m. President Peltier recessed the meeting until March 16, 2016 at 8:00 a.m. at which time the meeting reconvened with President Peltier continuing to preside and Secretary Gary C. Drost continuing to keep the minutes.

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, John Ciz, Kelly Cozby, Shawn Deisz, Tammy DeWitt, Ken Dolan, Mike Eggl, Brian Gardner, Matt Greek, John Jacobs, Steve Johnson, Kerry Kaseman, Becky Kern, Jon Klein, Janet Kubisiak, Brian Larson, Jim Lund, Tracy McBride, Gavin McCollam, Darla Miller, Dale Neizwaag, Deb Olafson, Curt Pearson, Dave Raatz, R.D. Reimers, Chad Reisenauer, Mike Risan, Ken Rutter, Darlene Steffan, Matt Stoltz, Steve Tomac, Val Weigel and Lyle Witham. Also present were DGC Vice President David J. Sauer and East River director Rick Koupal.

11. North Dakota Petroleum Council

Mr. Sukut introduced Ron Ness, President of the ND Petroleum Council, who discussed oil development in the Bakken. He outlined the number of infrastructure projects that have been or are being built. He said prices will need to be stronger before drilling begins to grow again. He noted even then, it will be a climb given the need for financing and the fact that the number of players has decreased dramatically.

12. Transmission Report.

Mike Risan, Senior Vice President, Transmission, reviewed the Transmission Department's safety activities for the past month.

As of February 29, 2016, Transmission System Maintenance Division (**TSM**) staff worked 90 days without a days away, restricted or transferred (**DART**) incident. TSM safety meetings are scheduled for March 10 in Gillette, March 15 in North Dakota, March 17 in South Dakota and March 29 in Wheatland.

Mr. Risan reported on Annual Transmission Revenue Requirement (**ATRR**) settlement conferences that were held at the FERC over the last month, as well as the schedule for upcoming conferences. Previously at issue were qualifying facilities, leases and return on equity. The remaining issues are now focused on return on equity, capital structure and depreciation.

He discussed the settlement conferences on February 22 and February 23. In the East River conference, FERC staff offered East River a 9.1% return on equity (**ROE**). East River countered with 9.8% ROE and introduced a hypothetical capital structure. FERC increased its ROE offer from 9.1% to 9.3%. East River countered with 9.6%. FERC declined. FERC staff also offered Basin Electric a 9.1% ROE and a 30% hypothetical capital structure. Our counter was 9.8% ROE with a 50% hypothetical capital structure. FERC also thought our depreciation should be extended. FERC increased their offer to 9.3%. There was a caucus and Basin Electric responded that the offer was so low, we did not think it was appropriate to respond and that we were concerned about the cross subsidization that would occur using this ROE.

On their March 1, 2015 conference call, East River offered a 9.6% ROE with a 40% equity level. FERC staff eventually countered, accepting the 9.6% ROE but with a 35% floor for equity level. East River conditionally accepted the FERC staff offer, subject to the approval of Missouri River Energy Systems.

FERC trial staff's behavior is more aggressive than expected and they seem to be taking more of a consumer advocate position than in the past. He noted this process is taking longer and is requiring more resources than we had expected. There is the possibility we may need to take our ATRR matter to hearing. Mr. Risan thanked the transmission group for their hard work.

He reviewed the North Killdeer Loop 345 kV transmission line project submission to SPP. SPP staff came back with a Kummer Ridge-to-Roundup 115 kV line versus the 345 kV line. There is an internal meeting at SPP today to review the new information we have submitted. We have also made the decision internally to slow down work on Phase II of the North Killdeer Loop project, to proceed acquiring right-of-way easements, but not to proceed with any condemnations. It was also decided to delay the siting permit submittal to the North Dakota Public Service Commission (**PSC**). SPP has also requested revised load forecasts for the area to be served by this line.

He reviewed the Williston Basin load pocket. He noted the drop-off in loads is due to warm weather and noted there are new gas processing plants coming on-line.

He presented the SPP Group Organizational Chart. SPP requested additional representation on the Strategic Planning Committee and Mr. Risan was appointed to this committee. The Board congratulated Mr. Risan on his appointment. This committee could be important in the formation of a west-side RTO.

He reported that the FERC jurisdictional participants in the Mountain West Transmission Group are Black Hills Corporation and Public Service Company of Colorado. The non-jurisdictional participants are Tri-State, Western Area Power Administration, Colorado Springs Utilities, Platte River Power Authority and Basin Electric. The entities are working on a Memorandum of Understanding. A meeting is scheduled with the FERC commissioners on May 4, 2016.

The NERC Critical Infrastructure Program Version 5 compliance date was delayed from April 1 to July 1. Staff is working on a facility matrix with the members identifying facilities and compliance responsibility.

13. Operations Report

John Jacobs, Vice President of Operations, reported there were three medical treatments and two DART incidents during the month. He provided bus-bar costs for the coal-fired fleet and reviewed the equivalent forced-outage rate trends for the past 24-month period. He reported that February generation for the owned and operated Basin Electric fleet came in at 2,056,214 MW compared to the budget of 2,336,552 MW, which is 12.0% below budget for the month. Generation for 2016 year-to-date is 9.7% below budget.

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

Unit	Availability	Running Plant Capacity Factor	Unit Rating	Comments
AVS #1	93%	81.3%	450 MW	Scheduled outage for boiler tube leak repair.
AVS #2	91%	82.8%	450 MW	Forced outage for boiler tube leak repair.
DFS	100%	97.42%	386 MW	
LRS #1	100%	67.89%	570 MW	
LRS #2	97%	64.38%	570 MW	Scheduled outage to replace condensate booster pump isolation valve. Forced outage when unit tripped on high drum level.
LRS #3	100%	86.47%	570 MW	
LOS #1	100%	68.38%	221 MW	
LOS #2	89%	70.80%	448 MW	Scheduled maintenance outage.

Mr. Jacobs reported that on March 6, 2016, the LOS coal stockpile contained 717,465 tons or 57.3 days of burn at cruise rates. As of February 29, the LRS stockpile contained sufficient coal for 39.2 days for all units at full load. He presented some photographs of the AVS #1 tube leak repair, the DFS Integrated Test Center and the LOS #2 outage.

A. Distributed Generation Update

Kevin Tschosik, Distributed Generation Manager, reported on the very low natural gas prices for the distributed generating facilities. There were two DART incidents at the distributed generation facilities during the month. February generation at the distributed generation facilities (Groton Generating Station (**Groton**), Culbertson Combustion Turbine (**CT**), Wyoming Distributed Generation (**WDG**), Spirit Mound Station (**SMS**), Deer Creek Station (**DCS**), Pioneer Generating Station (**PGS**) and Lonesome Creek Station (**LCS**)) was as follows:

Unit	Monthly Availability	Monthly Generation	Unit Rating	Comments
Groton #1	93.4%	584 MWh	100 MW	
Groton #2	94.4%	4,080 MWh	100 MW	
Culbertson CT	89.87%	4,532 MWh	100 MW	
WDG	99.62%	54 MWh	54 MW	
SMS #1	0%	0 MWh	60 MW	Did not run
SMS #2	0%	0 MWh	60 MW	Did not run
DCS	97.35%	73,520 MWh	300 MW	
PGS #1	93.4%	5,834 MWh	45 MW	
PGS #2	99.36%	6,305 MWh	45 MW	
PGS #3	98.77%	5,430 MWh	45 MW	
LCS #1	81.9%	11,398 MWh	45 MW	
LCS #2	46.39%	8,930 MWh	45 MW	
LCS #3	81.06%	16,723 MWh	45 MW	

During February, the PGS ran 453.93 hours in synchronous condensing mode and the LCS for 4.42 hours.

The WDG had 19 west-side spinning reserve events for the month.

<u>PrairieWinds ND (**PWND**)</u>. Icing conditions resulted in the loss of 790 MWh.

<u>PrairieWinds SD (**PWSD**)</u>. Icing conditions and the high-voltage transmission outage repairs resulted in the loss of 2,167 MWh.

The east-side peak occurred on February 8, 2016 at 0800 hours. At that time, wind generation was as follows:

Wind Project	Load Factor during the Peak	Capacity Factor		Project Total
		Month	YTD	
Baldwin	19 MW%	34%	36%	100 MW
Campbell County	0 MW	35%	35%	94 MW
Day County	32 MW	50%	44%	99 MW
Edgeley	4 MW	29%	25%	40 MW
Highmore	1 MW	40%	35%	40 MW
Iowa Wind	27 MW	49%	45%	45.1 MW
Other Projects (Chamberlain & Pipestone)	0 MW	53%	41%	3.4 MW
PWND	21 MW	39%	40%	123 MW
PWSD	9 MW	44%	41%	162 MW
Wilton	25 MW	29%	32%	99 MW
Total Monthly Wind Generation	137 MW			805 MW maximum
Average Capacity Factor		40%	38%	

B. LRS Plant Update

Brian Larson, LRS Plant Manager, reported on LRS workforce statistics and noted that there were no DART incidents in February. Forty percent of the LRS employees have one to five years of experience. The average age of these employees is 27. He reminded the directors that the LRS awards banquet recognizing 35- and 45-year employees is on April 7th. He stated LRS employees had worked over 250,000 man-hours without a DART incident.

Kelsey Arcocha, Environmental Coordinator Assistant, reviewed the 2015 LRS Our Power, My Safety annual report including employee participation, positive comments, continuous improvement inspection work and a comparison with 2014 statistics. She then reviewed and presented photographs of 2015 Initiative Integration Team Activities. She then reviewed activities planned for 2016.

Mr. Larson reported that year-to-date, LRS has exceeded all of its environmental compliance goals and reviewed statistics for each unit for NO_X, opacity, SO_2 and percent of SO_2 allowances consumed. He then reviewed year-to-date production statistics, availability and outages. As of February 29, 2016, the stockpile contained an estimated 1.1 million tons which is sufficient for 34.2 days operating at full load. The Grayrocks Reservoir is currently 102.7% full at 4,404.8 feet Mean Sea Level. The snow pack report as of March 2, 2016 is at 90% to 110%. Projects planned for the LRS #2 outage (April 16 - May 29, 2016) include low-pressure turbine rotor L-0 buckets, replacement of air heater baskets and air heater lube oil skid, absorber tower overhauls, replacement of absorber bowl return lines, economizer inlet header, cooling tower switch gear, circulating water piping repairs and cooling tower fan motor variable speed drives.

Mr. Larson then presented photographs and discussed the generator step-up unit (**GSU**) project and the fuel oil storage tank. He thanked TSM for helping make the GSU move go so smoothly.

C. LRS Bulk Warehouse Update

Mr. Larson reported that a new warehouse is needed to make room for construction of the LRS #1 selective catalytic reduction (**SCR**) system. The new warehouse will be used for the SCR catalyst storage, to consolidate and to improve on-site storage and to enhance equipment reliability. The new warehouse will have 54,000 square feet of unheated space, including 5,000 square feet for the SCR catalyst, 4,000 square feet for electric motors and 7,000 square feet consolidation storage. He presented a diagram of the plant site showing the location of the old and new warehouses and recommended that Capital Project Request #200266 be opened at an estimated cost of $6,655,000.

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

R01.03-15-16 RESOLVED, that LRS CPR 200266 be opened for the new Bulk Warehouse at Laramie River Station at an estimated cost of $6.55 million ($2,808,410 Basin Electric portion); and

BE IT FURTHER RESOLVED, that the CEO and General Manager, or his designee, is hereby authorized to execute the necessary documentation.

D. LRS Bulk Warehouse Contract Award

Jim Lund, Senior Project Manager, reviewed the building specification for the new bulk warehouse which calls for a pre-engineered building on grade slab, 180 feet by 300 feet, with no heat, 120-volt electrical service and insulated wall and roof panels. The scope of this contract includes site preparation and building substructure, building design and supply and building installation (electrical, HVAC and fire protection). He reviewed the three bids received and recommended that the contract be awarded to Ormond Construction, Inc. at a cost of $4.50 million, of which $1,902,620 is Basin Electric's cost. The approved project budget is $6.655 million.

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

R02.03-15-16 BE IT RESOLVED, that the contract for the LRS Bulk Warehouse Supply and Installation be awarded to Ormond Construction, Inc. in the amount of $4,502,578 ($1,902,620 Basin Electric cost); and

BE IT FURTHER RESOLVED, that the CEO and General Manager, or his designee, is hereby authorized to execute the necessary documentation.

14. Risk Management Report

Kerry Kaseman, Manager of Commodity Risk, reported that during the month, the Risk Management Steering Committee (**RMSC**) approved the natural gas hedge plan for 2018:

- Previously approved volumes of 15,000 MMBtu/day
- Increase volumes by 7,500 MMBtu/day
- Total expense secured $20.4 million
- Total risk mitigated $14.9 million

The current natural gas current hedge position for 2016 is $1.77 and the 2017 natural gas hedge position is at $2.99.

He reviewed the Ventura Forward Curve which, as of March 1, 2016, starts at $1.96/dkt for 2016 increasing to $2.84/dkt for 2020 and was down on average about $0.19 from last month.

March settled financial hedges for power resulted in a loss of $(129,580). He reviewed the Mark-to-Market (**MTM**) of $13.5 million for natural gas and the current hedge position of natural gas.

He reported that March settled financial hedges for power resulted in a loss of $(138,139). He reviewed the Palo Verde On-Peak Forward Curve which, as of March 1, 2016, started at $14.68/MW for 2016 and increased to $23.20/MW for 2020. He noted that the forward prices had dropped significantly over the month. He reviewed the MTM of $652,000 for power. He reviewed the current hedge position-west surplus sales, which reflected a 2016 average hedge price on-peak of $24.74 and off-peak of $17.06.

He noted there are currently no hedges in place for east-side purchased power.

He reviewed the Energy Information Agency's on-highway diesel price projections which, as of March 1, 2016, started at $2.17/gallon increasing to $2.75/gallon for December 2018 and saw minimal movement during the month. The March settled financial hedges for diesel resulted in a loss of $(8,169). The diesel MTM as of February 29, 2016 was

$140,000. All commodities settled at $(475,888) for the month and $(412,641) for the year-to-date. MTM all commodities as of February 29, 2016 was $(12.7) million.

He then reviewed the MTM for all commodity hedges, the liquidity position and credit exposure broken down by Moody's credit ratings.

15. Marketing & Asset Management--March 2016 Short-Term Market Summary

Ken Rutter, Vice President Marketing & Asset Management reported on the North Hub, Minnesota Hub and Palo Verde 2016 pricing. Power prices at SPP North fell 20% month over month for the remainder of 2016. He stated staff is having discussion regarding economics of running LOS with the prospect of long-term low natural gas prices. He noted that the drop in natural gas prices and resulting changes in dispatches have resulted in reducing prices within our load zone. He reported the day-ahead average of $16.74 and real-time average of $14.98 were both very low prices, especially for February. He presented the February weather and loads for Bismarck, Sioux Falls and Great Falls. This has been the warmest start to winter in the past five years per Bentek statistics.

Brian Gardner, General Load Quantity Analyst II, then reviewed Basin Electric's wind portfolio which currently totals 804 MW. He reviewed the portfolio performance in SPP from October 2015 through February 2016. February had the lowest locational marginal pricing due to low energy prices. He presented an example of financial impact of icing on January 8, 2016 with a cost of deviation of $(14,000). SPP currently has 12,380 MW of wind installed. By the end of 2016, SPP will add 4,500 MW of new wind installations, of which 556 MW will be owned by Basin Electric across four projects: Lindahl (150 MW), Brady (150 MW), Brady 2 (150 MW) and Sunflower (106 MW). SPP peak wind supply as a percentage of load was 43.5% as of March 14, 2016. Studies done by SPP show that up to 60% of load could be supplied by wind without undermining grid reliability. Wind makes up about 14% of SPP generating capacity. Given this very large amount of wind capacity, he stated that it was going to be difficult to put the genie back in the bottle.

16. Recess and Reconvention

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

17. 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, Dean Bray, Andy Buntrock, John Ciz, Shawn Deisz, Tammy DeWitt, Ken Dolan, Mike Eggl, Pius Fisher, Matt Greek, John Jacobs, Casey Jacobson, Steve Johnson, Kerry Kaseman, Becky Kern, Jon Klein, Matt Kolling, Joe Leingang, Sharon Lipetzky, Russ Mather, Tracy McBride, Gavin McCollam, Darla Miller, Mary Miller, Dale Neizwaag, Deb Olafson, Diane Paul, Curt Pearson, Dave Raatz, R.D. Reimers, Josh Rossow, Jim Sheldon, Susan Sorenson, Myron Steckler, Darlene Steffan, Steve Tomac, Katrina Wald, Val Weigel, Cheri Wenzel, Roxanne Woeste and Mike Zimmerman. Also present were DGC Vice President David J. Sauer and East River director Rick Koupal.

18. Project Dominoes

Susan Sorensen, Vice President & Treasurer, reported on the coal impacts of reduced dispatch of LOS and AVS. She noted lowering dispatch only shifts fuel expense as other larger costs such as depreciation, interest expense and labor do not go away. The Project Dominoes directives were: "that even with that family perspective, we can still manage the short-term daily offers to the market once we all agree on an acceptable threshold of value for a one week shutdown at LOS; and in doing so, to be fair and objective. She defined the project team steps and scope limitation (first to study LOS and DCS)." The effort was to do a complete financial study of total fixed and variable costs at LOS and DCS. To do so, they pulled in Cooperative experts Kevin Tschosik for DCS, Jamey Backus for LOS, Bob Bartosh and Dean Bray for Dakota Coal Company (**DCC**), Kent Vernon, Carroll Dewing and Kent Neustel for The Coteau Properties Company (**Coteau**) and Matt Ehrman and Craig Steffan from Engineering. She reviewed the details of the model that the team created.

She reviewed the project assumptions: (1) tight correlation between DCS and SPP North; (2) DCS represents Ventura gas pricing; and (3) the ability to draw a line from Ventura gas prices to SPP North Hub prices.

Based on those prices, the goal was to use DCS as a proxy to find the market gas price where coal gets displaced by gas (consolidated) and knowing the dispatch offer order from LOS #1 and #2, solve for market power price where breakeven occurs. She presented the baseline assumptions. The model includes functionality to adjust these assumptions. She presented two scenarios where the gas price stays constant with the conclusion that at $2.65 gas it is more favorable to run coal over gas. She presented two more scenarios where the gas price decreases to $1.00 with the conclusion at $1.65 gas that it is more favorable to run coal over gas. She presented another scenario where the gas price hits $1.14 with the conclusion that at $1.14 gas converges to coal. She presented another scenario where LOS does not run and surplus sales decrease and assumes market power price of $23.83. The conclusion is that it is more favorable to run coal at a loss to recover some level of fixed costs. The conclusion is if replacement power can be purchased at less than the variable cost to produce, it's economic and under present circumstances, if the market price is $13.75 or higher, to generate out of LOS and at a price below $13.75, to shut down LOS and purchase.

Mr. Rutter presented the marketing view of LOS economics. At the outset, it is important to keep in mind that generation and load settlement in an RTO market are distinct but generation is a financial offset to load costs.

Finance's comprehensive look suggests that LOS and DCS have to recover the minimum variable costs from the market with LOS $13.75/MWh and DCS $17.09/MWh, however, the market is what the market is. Basin Electric's generation represents only 4% of the total capacity in SPP. Our units must be competitive against the other 96% of SPP capacity to support higher capacity factors. The market provides revenue opportunities for energy, capacity (no market, but defined requirements) and ancillary services.

LOS and DCS are no longer interchangeable. In an organized RTO market, our members benefit by having access to potentially cheaper energy from the market than we can generate or the members benefit by making surplus sales via market access. We no longer look at our position such that we serve our load from just our generation assets. Our generation assets have become financial offsets to our load costs.

Marketing's objective with respect to the cost of serving our load is to sell our units into the market at or above incremental cost. In SPP, incremental cost is defined as startup, no load, fuel (using incremental heat rate) and some variable operations and maintenance costs. If our units have economic output volumes in excess of our loads, this leads to a surplus and we will sell the excess into the market. If our units have economic output volumes below our loads, this leads to a shortfall and we will buy the short position from the market. This strategy has proved viable and more profitable for Basin Electric for the first 5.5 months of entry into SPP than past practice.

He reviewed the four-part generation fleet offer strategy and noted that each unit is stand-alone versus its market price. Each unit will be paid its own unique Locational Marginal Price (**LMP**). Each unit's offer price is scrubbed to understand its incremental cost. If the market can beat any unit's LMP, then Basin Electric benefits by serving our load cheaper from the market.

To date, LOS offers have included the all-in fuel cost as reported internally. With the completion of the Finance Department's analysis, Marketing will adjust its unit offers for LOS removing the fixed costs from mine. This will make LOS more competitive in the market. He presented the LOS versus market purchases using LOS day-ahead LMP pricing.

Wind, cheaper coal and natural gas are displacing LOS in the market. Wind is typically offered at no cost, or even negative pricing due to the production tax credits. Other coal plants in the markets are treating take-or-pay coal contracts as fixed costs and excluding that cost from their incremental offer. Natural gas prices in Oklahoma tend to average approximately $0.20/MMBtu below Ventura. On a unit with an eight heat rate, this equates to $1.60/MWh. Coal units are being backed down to minimums. He reviewed the capacity factors which have been lower than budget for the coal-fired units and higher than budget for the combined-cycle and gas-peaking units.

Concluding, he stated that the AVS and LOS offers will be revised to remove mine fixed costs. We will look for opportunities to perform maintenance at LOS if the market is projected to be below the offer cost.

There have been many market participants (MidAmerican, Tri-State, Ameren, Dynegy and ERCOT) taking short economic shutdowns to take advantage of low market pricing. Coal-fired generation has dropped below nuclear generation three times this year. Before this year, coal generation had only fallen below nuclear once for a short period (five days) with data back to 2003.

Basin Electric was a net buyer in SPP for the month of February to serve loads from SPP in SPP, Montana and MISO. He reviewed February estimated marketing outcome versus budget, which resulted in a net $6.5 million favorable variance over the budget.

Mr. Rutter reviewed the Basin Electric hedge plan notional values and natural gas hedge plans executed 2017-2021. The hedge plan for 2018 targets 8,212,500 MMBtu/year. The hedge plan for 2019-2021 targets 5,475,000 MMBtu/year. He reviewed the total 2016 through 2021 natural gas hedges.

19. Cooperative Planning, continued

A. RFP Response

Mr. Raatz continued his Cooperative Planning report noting that the 2016 power supply Request for Proposals (**RFP**) was released on February 11; the notification of intent to bid deadline was February 19; the bid submittal deadline was March 8; the notification of shortlist of bidders will be on April 8; and decisions will be made in early June. We received 85 purchase proposals to the RFP and three sale proposals. Of the 85 purchase proposals received, 6,669 MW were for wind, 551 MW were for solar, 175 MW were for market power, 1,646 MW were for a specific resource, two were for energy only and one was for transmission. Three sale proposals were received for power from LRS.

B. WMPA Update

Mr. Raatz reviewed the results of the analysis conducted by the Wyoming Municipal Power Agency (**WMPA**) on becoming a member of Basin Electric. WMPA stated that while there are certain advantages to being part of a larger organization, the large increase in Basin Electric rates Burns & McDonnell is projecting dictates staying their present course. WMPA and staff expressed appreciation for the opportunity to examine full membership.

C. Montana Cooperatives

He reported that Mid-Yellowstone Electric Cooperative, Tongue River Electric Cooperative and Fergus Electric Cooperative have indicated interest in joining Basin Electric earlier than the present October 1, 2017 start date. The parties are exploring how that start date could be moved up to October 1, 2016.

D. Minnkota Membership

Mr. Raatz reported on the March 2 meeting with Minnkota Power Cooperative (**Minnkota**) which resulted in a schedule calling for a term sheet by late summer 2016, a decision on direction by January 1, 2017, execution of agreements during the second quarter of 2017 and rate/combined operations by April/June 2017. The Minnkota rate schedule goes into effect April 1, 2017. The Midwest Independent System Operator (**MISO**) contract year becomes effective June 1, 2017.

E. Rate Subcommittee

Mr. Raatz reported that topics of discussion at the March 7 Rate Subcommittee meeting were general rate structure, energy market load management, solar generation, PURPA assignment and an update on the CPP. It was concluded that no change in the time of the member billings peak was warranted at this time and the group supported free demand periods.

The managers' group supported elimination of the member power cost cap and supported maintaining the 50/50 base rate demand/energy split and the 56%/44% fixed CROD demand/energy split. He reviewed the historical and forecast fixed and variable rate base cost of service and noted that the Rate Subcommittee had supported maintaining the existing incentive rates.

There was a significant discussion on discounted rates for loads inside defined service territory and loads outside defined service territory. The managers were not receptive to discounted rates within service territories (Class C members).

Additional discussion is required on general Rate Schedule A modifications to sell power to the members for loads outside their defined service territory. The managers did support making a market-based surplus sale to Corn Belt Power Cooperative (**Corn Belt**) for the municipality of Pocahontas, Iowa for 3 MW. Discussion regarding timeframe and contract specifications followed.

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

<u>**R03.03-15-16**</u> RESOLVED, that the Board of Directors authorizes making a market-based surplus sale to Corn Belt Power Cooperative (**Corn Belt**) for power and energy to serve the Municipality of Pocahontas, Iowa (**Pocahontas**) to replace the expiring contract between Pocahontas, Iowa Lakes Electric Cooperative and Corn Belt.

BE IT FURTHER RESOLVED, that the Board of Directors directs staff to develop and present proposed modifications to Rate Schedule A to sell power to members for loads located outside their defined service territories.

F. Renewable Resource Policy

Mr. Raatz presented Board Policy #01, Renewable Resource Obligations, with the changes recommended by the board at its meeting last month and recommended it be approved.

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

<u>**R04.03-15-16**</u> RESOLVED, that Board Policy #01, Renewable Resources Obligations, is hereby approved.

G. Nemadji Trio Energy Center Project Authorization

Becky Kern, Director of Utility Planning, reported that the Nemadji Trio Energy Center (**NTEC**) will be an 885 MW combined-cycle facility owned by Basin Electric and two other utilities. If Basin Electric runs 33.3% of the unit, it will cost between $325 million and $375 million.

The project is needed because it will provide capacity and energy to meet our obligations. She reviewed our obligation in MISO via an energy graph showing load obligation, baseload generation and market exposure in 2023. The NTEC unit will meet that need. She reviewed the anticipated, prospective and reference-margin level reserve margin for the entire MISO region from 2016 through 2025. Today, the reference-margin level is 14.3%.

Ms. Kern then compared the economics of the NTEC project to a Basin Electric-only stand-alone 400 MW combined-cycle unit, reporting a 2016 through 2040 net present value savings of $100 million (with a six percent discount factor).

She then discussed upcoming activities and project communications as well as the commitment timeline. The project agreement vote was on March 10; nominations are due May 27; the CEO meeting is on June 10 and the effective date of the new agreements is July 1. She then presented a draft resolution and recommended it be approved.

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

R05.03-15-16 BE IT HEREBY RESOLVED, that the CEO and General Manager of the Cooperative or his designee is hereby authorized and empowered to take the following action on behalf of the Cooperative:

1. Take all actions necessary to authorize and empower the Cooperative's wholly owned Wisconsin subsidiary, Nemadji River Generation, LLC (**Nemadji**), to take all actions, execute and deliver all documents and instruments and incur all expenses necessary or helpful to nominate and commit to acquisition of an undivided ownership of such percentage of the proposed Nemadji Trio Energy Center combined cycle generation project (the **Project**) as he deems to be in the best interests of the Cooperative; provided that such ownership interest shall not represent more than 400 megawatts. Such actions shall include, but shall not be limited to, execution and delivery of all Project agreements and all other associated documents and instruments relating to the design, construction, ownership and operation of the Project (collectively, the **Project Agreements**).

2. Execute and deliver on behalf of the Cooperative, a parental guaranty of full performance by Nemadji of all of its obligations under and pursuant to all of the Project Agreements.

H. PURPA Assignment

Ms. Kern and Casey Jacobson, Senior Staff Attorney, reviewed the member assignment of Public Utilities Regulatory Policy Act (**PURPA**) obligation to Basin Electric and noted that the waiver process will benefit our members by having Basin Electric interact with the larger qualifying facilities, saving the members time and money. The waiver process requires the adoption of a Joint PURPA Implementation Plan and providing public notice in the members' service areas of Basin Electric's intent to file for waivers. Once the Joint PURPA Implementation Plan is adopted and notice is provided, Basin Electric will file the petition with the FERC.

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

R06.03-15-16 WHEREAS, the Federal Regulatory Commission (**Commission**) Public Utility Regulatory Policies Act (**PURPA**) regulations generally require all electric utilities, including Basin Electric Power Cooperative (**Basin Electric**) and its members, to purchase power from and to sell power to "Qualifying Facilities". Notwithstanding, 18 CFR Section 292.402 provides that an electric utility may, after public notice in the area served by the electric utility, apply for a waiver of the purchase and sale requirement, and the Commission may grant a waiver if the electric utility demonstrates that compliance with such requirement "is not necessary to encourage cogeneration and small power production and is not otherwise required under PURPA; and

WHEREAS, Basin Electric and its all-requirements members, with the exception of Tri-State Generation and Transmission, Inc. (**Tri-State**) desire to seek a waiver of the PURPA obligations, for our members, on any Qualified Facility of 150 kW or more.

NOW THEREFORE, BE IT RESOLVED, that the Board of Directors hereby authorizes the Chief Executive Officer & General Manager, or his designee, to arrange for the submission of the Joint Implementation Plan for the PURPA waiver to the Commission on behalf of all of Basin Electric's members except Tri-State.

20. Engineering & Construction Report

A. Project Funding Chart

Matt Greek, Senior Vice President-Engineering and Construction, reported that three contracts totaling $5 million would be presented for approval this month. He then presented the listing of all current major projects along with the approved budget amount, total dollars committed and completion dates.

B. Allam Cycle Update

Mr. Greek reported that Minnesota Power, 8 Rivers, U.S. Department of Energy (**DOE**), the North Dakota Lignite Energy Council (**LEC**), the Energy & Environmental Research Center (**EERC**) and Basin Electric are participating in a study on the Allam Cycle development on coal. Phase 1A is Research & Development. Four key research and development areas have been identified by EERC and 8 Rivers: (1) metallurgy/corrosion, for which testing has begun; (2) gasifier selection, for which a long list has been created; (3) impurity removal, which is in progress; and (4) syngas combustor, which is in progress.

The $5 million LEC grant application was submitted on October 1, 2015. Phase 1A Research & Development work is scheduled for January through November 2016. The total Phase 1 cost estimate is $3.18 million, of which Basin Electric provided $125,000 in cash and $25,000 in-kind. $1.48 million of the LEC grant is to be used to partially fund Phase 1A.

Mr. Greek reported that the application for state funding is due April 1, with voting on May 19, 2016. The scope of the application includes the syngas combustor testing and build-off of main tasks in Phase 1A. One-half of the cash contribution is due in June 2016 and the second half in 2017. He reviewed the Phase 1B targeted cost breakdown, which includes $250,000 cash and in-kind donations from Basin Electric and ALLETE, Inc., $3.5 million LEC grant and $3 million from the DOE (via EERC and 8 Rivers) for a total of $7 million for Phase 1B. He noted this breaks down to a

$250,000 contribution by Basin Electric to leverage a $7 million research and development effort.

C. Lonesome Creek Station Phase III Update

Josh Rossow, Project Manager II, reported there have been no safety or environmental incidents in more than three months at LCS. LCS III project costs are at 87.4% of forecast. The approved project budget is $107.9 million. Construction progress to date includes switchyard energization on February 12, mechanical completion on February 19, backfeed on March 11 and first fire the week of March 21. The projected completion date is April 4, 2016.

He then presented photographs of LCS Units #4 and #5, the warehouse building, the 115 kV switchyard and Phase III transmission structures.

D. Pioneer Generation Station Phase III Update

Mr. Rossow reported there were no environmental incidents and two first-aid incidents at PGS III in February. To date, construction progress includes delivery of engines November 1-9, 2015 and switchyard energization and mechanical completion on March 7. Backfeed is anticipated for March 19.

The commissioning schedule calls for balance-of-plant equipment commissioning March 19-April 9, Wartsila pre-commissioning March 31 to April 25, engine first start and load testing April 25 to June 10 and final acceptance tests June 10-June 22. The projected completion date is June 22, 2016.

He presented photographs of an engine arriving on site and being slid into place, the engine and catwalks and control room operator console.

PGS Phase III project costs are at 88.6% of forecast. The approved project budget is $161.2 million with $8.4 million contingency. The project is currently $22 million under budget.

E. Amendment to PGS Phase III Mechanical Installation Contract

Mr. Rossow reported that change orders to the mechanical installation contract with Casey Industrial Inc. are needed due to engineering completion after the contract award, rework due to engineering errors, Basin Electric-requested scope changes and backcharges to others. The original authorized contract value was $11,692,638. Change orders to date total $940,326. The estimated additional change orders to complete the contract are $1,071,582 for a new requested total of $13,704,546. He recommended approval of the amendment.

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

R07.03-15-16 RESOLVED, that the authorized contract amount for the PGS Phase III Casey Industrial Mechanical Installation contract be amended from $11,692,638 to $13,704,546, an addition of $2,011,908; and

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

F. Amendment of PGS Phase III Electrical Installation Contract

Mr. Rossow reported that change orders to the electrical installation contract with Saulsbury Industries are needed due to engineering completion after the contract award and Basin Electric-requested scope changes. The original authorized contract value was $5,665,864. Change orders to date total $711,202. The estimated additional change orders to complete the contract are $1,144,545 for a new requested total of $7,521,611. He recommended approval of the amendment.

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

R08.03-15-16 RESOLVED, that the authorized contract amount for the PGS Phase III Saulsbury Industries Electrical Installation contract be amended from $5,665,864 to $7,521,611, an addition of $1,855,747; and

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

G. LOS SNCR Project Update

Mr. Lund reviewed the project background, noting that the North Dakota Regional Haze State Implementation Plan includes 30% NO_x reduction for Unit #1 and 43% NO_x reduction for Unit #2 with a March 2017 compliance date.

Selective Non-Catalytic Reduction (**SNCR**) technology was selected as the lowest cost NO_x reduction option. This SNCR project was approved in July of 2014, with a Unit #1 cost of $9.34 million and Unit #2 cost of $25.96 million.

The design and procurement phase is 95% complete with the balance-of-plant equipment installed, SNCR process equipment waiting for injection nozzles (April) and the as-built drawings and on-site training to be completed after construction.

The general works contract includes SNCR building substructure and construction- HVAC and exterior trim, mechanical equipment and piping (85% complete), power supply equipment and wiring (55% complete) and controls equipment and wiring (70% complete). This contract is scheduled to be turned over to commissioning in May.

He presented photographs of construction from August 2015 through March 2016, the second floor of the SNCR building, the urea metering skid, the urea distribution skid and the urea tubing to the boiler.

The Unit #1 project cost summary includes the budget of $9,340,545, committed expenses of $8,818,970 and remainder of $521,575.

The Unit #2 project cost summary includes the budget of $25,958,890, committed expenses of $23,825,791 and remainder of $2,133,098.

H. Amendment to LOS SNCR General Works Contract

Mr. Lund reported that an amendment to the LOS SNCR general works contract is needed due to the decision to proceed with the request for proposal to meet the summer construction window without fully completed electrical design and required field changes to complete construction. The original authorized contract value was $12,429,127. The amendment is for $874,792. The contract limit is $13,672,040.

The current contract amount is $13,303,919. He recommended approval of the amendment.

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

R09.03-15-16 RESOLVED, that Contract #691316 (LOS SNCR General Works Contract) is hereby amended to increase from $12,429,127 to a new contract total of $13,303,919; and

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

21. Recess and Reconvention

At 4:55 p.m., President Peltier recessed the meeting until March 17, 2016 at 8:00 a.m., at which time the meeting reconvened with President Peltier continuing to preside and Secretary Gary C. Drost continuing to keep the minutes.

22. Roll Call

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

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

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, Dean Bray, Andy Buntrock, Shawn Deisz, Tammy DeWitt, Ken Dolan, Mike Eggl, Matt Greek, Jen Holen, John Jacobs, Steve Johnson, Kerry Kaseman, Becky Kern, Mark Kinzler, Jon Klein, Matt Kolling, Joe Leingang, Sharon Lipetzky, Tracy McBride, Sally Meier, Karla Merkel, Darla Miller, Kimberly Miller, Mary Miller, Diane Paul, Shawna Piatz, Dave Raatz, Chad Reisenauer, Ken Rutter, Marci Schorsch, Christy Dirk-Senn, Susan Sorenson, Darlene Steffan, Steve Tomac, Katrina Wald, Val Weigel, Cheri Wenzel and Roxanne Woeste, Tiffany Zablotney and Mike Zimmerman. Also present were DGC Vice President David J. Sauer, East River director Rick Koupal and IHI-CERA Vice President Jim Burkhard.

23. IHS - Oil & Gas Price Forecasts

Andrew Buntrock, Manager of Financial Planning and Forecasting, introduced Jim Burkhard, Vice President of Oil Markets and Energy Scenarios for IHS-CERA, who made a presentation on IHS-CERA's forecast of energy commodity prices. He noted this is the worst oil downturn since the 1980's. A steep decline in new oil production investment is setting the stage for rising oil prices from $38 per barrel for WTI in 2016 to $80 by 2020. U.S. crude production is expected to continue to fall through at least mid-2016. Liberalization of U.S. crude oil exports and new pipelines reduce the risk of wide price spreads between the Bakken and West Texas Intermediate. The potential for greater production efficiency and lower development costs could keep oil prices lower than expected. U.S. oil production has fallen 4% since April 2015. He reviewed U.S. and

North Dakota crude oil production from 2010 through 2016. IHS-CERA anticipates demand will exceed supply sometime in the second quarter of 2016. Non-OPEC crude oil supply growth turns negative as lack of investment takes hold. U.S. production is expected to fall by 600,000 bbs/day.

As to the North American natural gas market outlook, the U.S. lower 48 natural gas resource base is even larger than thought just 10 years ago. He presented the Henry Hub price outlook to 2026. Upstream oil and gas investment in North America will decline for a second consecutive year for the first time since the 1980's. Many companies are spending 40% to 60% less in 2016 compared to 2015. Falling investment is the key to oil prices rising in 2017-2020 but natural gas prices are likely to remain low. Some companies must sell assets or raise debt to survive. Oil prices are prone to heightened volatility since there is little spare production capacity and OPEC is no longer attempting to manage supply.

24. Communications & Administration Report

Mike Eggl, Senior Vice President - Communications & Administration, provided an update on activities associated with educating the membership and employees about the CPP. There was a Senate Budget Hearing on the DOE's budget on March 3. Staff worked with North Dakota Senator Hoeven on what type of financial assistance (not loan guarantees) is available from DOE to help fund the actual construction of a large-scale demonstration greenfield plant utilizing advanced power systems like the Allam Cycle and the kind of support the DOE is giving to the development of enhanced oil recovery to further utilize North Dakota's shale geology. DOE Secretary Moniz has requested a briefing on the Allam Cycle.

It was announced on March 9 that ground was broken on a natural gas Allam Cycle project near Houston. This 25 MW natural-gas pilot power plant is being developed by Net Power and is expected to be on-line in 2017. He noted the potential for a tour of this site by North Dakota legislators in 2016.

Mr. Eggl then presented a video of a local television station interviewing Dale Niezwaag on the CPP and an audio clip from the DOE hearing.

He noted that staff is tracking 66 bills in the Wyoming legislature this session. One bill which was classified as a priority is SB41, which included a provision the Cooperative supported to help finance coal-impacted road reconstruction, specifically Garner Lake Road near the Dry Fork Mine.

Mr. Eggl then reported on activities associated with the "Brave the Shave" fundraiser in support of the St. Baldrick's Foundation and "Be the Light". A discussion followed regarding the Touchstone Energy brand and board governance.

A. Action on Board Policies #05 and #06

Mr. Eggl reviewed the Basin Electric governance structure. He reviewed the Board policy review schedule and status. Board policy #01 was approved by the Board earlier at this meeting. No changes were recommended to Board Policy #05, Manager's Advisory Committee. The recommendation was to eliminate Board policy #06 Transmission.

After discussion, it was moved by Director Drost, seconded by Director Pearson, and carried to approve the following Resolution:

R10.03-15-16 RESOLVED, that Board Policy #05, Managers Advisory Committee, is hereby adopted as presented; and

BE IT FURTHER RESOLVED, that Board Policy #06, Transmission Policy, is hereby eliminated.

25. Human Resources & Development Report

Diane Paul, Senior Vice President - Human Resources & Development, provided updates on deferred compensation and benefits. She reviewed Blue Cross/Blue Shield 2015 enrollment data, age and gender demographics, the average cost per covered life, inpatient hospitalizations, average days per claim by type of service, the stop-loss analysis and brand name drugs versus generic prescription drug coverage utilization. She noted that staff is currently requesting bids from insurance brokers to assist the Cooperative with its benefit plans.

A. Investment Committee Membership

Steve Johnson, Senior Vice President & Chief Financial Officer, recommended that a new resolution be adopted with respect to the members at large on the Investment Committee to include the positions and names of the people serving on that committee.

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

R11.03-15-16 WHEREAS, the Basin Electric Power Cooperative and the Dakota Gasification Company Boards of Directors (the "Boards") formed the Investment Committee to provide guidance on the operation and administration of the Basin Electric Power Cooperative 401K Plan, Basin Electric Power Cooperative ND/SD Union 401K Plan, Basin Electric Power Cooperative WY/NE Union 401K Plan and Dakota Gasification Company 401K Plan (collectively, the "Plans"); and

WHEREAS, the Charter for the Investment Committee provides that each member of the Committee shall be appointed by the Boards and the Boards shall designate one member of the Investment Committee to serve as chair.

BE IT RESOLVED, that the Board of Basin Electric Power Cooperative does hereby authorize the appointment to the Investment Committee of the following positions: CEO & General Manager (Paul M. Sukut), Senior Vice President & Chief Financial Officer (Steve Johnson); Senior Vice President & General Counsel (Mark D. Foss); Senior Vice President of Human Resources (Diane Paul); DGC Plant Manager (Dale Johnson); Vice President Operations (John Jacobs), AVS Plant Manager (Chad Edwards); Director of Utility Planning (Becky Kern); and two "At Large" members, Susan Sorensen and Shawna Piatz; and

BE IT FURTHER RESOLVED, that the chair of the Investment Committee shall be the Senior Vice President & Chief Financial Officer.

Lynn Beiswanger, Director Learning & Development presented a learning and management update. The information and learning management system went live on March 1 and was successfully launched.

Power Plant 101 at Bismarck State College (**BSC**) is scheduled for March 23 & 24, 2016.

The target approval date for the apprenticeship program is next week. Chad Edwards, AVS Plant Manager, and Jamey Backus, LOS Plant Manager, are involved in this program. BSC initiated the curriculum for this program.

The "People Power Purpose" series are scheduled the Friday after every board meeting. Director Peltier feels this is a great series.

Mr. Beiswanger is working with Communications & Administration on the new employee orientation WebEx.

26. Financial Services Report

Mr. Johnson reviewed current economic statistics, liquidity, recent ratings actions of other companies and interest rate hedges and noted that Deloitte & Touche will review its audit with the board this month. The Member Investment Program reached a record high of $279.4 million during the month.

He reported on the U.S. Treasury yield curve for five, 10 and 30 years. He presented a graph of historical treasury rates from 2009 through 2016 and credit spreads from 2011 to present. Strong credits saw significantly less widening relative to their lower rated peers. Utilities continue to outperform other sectors amid a choppy backdrop. He presented the private placement spread by rating and maturity and utility credit spreads by rating and maturity. He presented indicative pricing for a $75 million term loan from the National Rural Utilities Cooperative Finance Corporation with a benchmark rate quoted as of March 3, 2016 with closing scheduled for May 1, 2016.

He presented the CoBank ACB (**CoBank**) financial results for 2014, 2015 and percentage of change. He reviewed the CoBank patronage distribution for Basin Electric, DCC and DGC.

A. $100 Million Term Loan Facility with CoBank

Matthew Kolling, Senior Staff Attorney, recommended the adoption of resolutions to authorize the CoBank $100 million loan transactions.

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

R12.03-15-16 WHEREAS, Basin Electric Power Cooperative (the **Cooperative**), under its articles of incorporation, bylaws, and other organizational documents has full power and authority to borrow money and to secure the same with its own property and property delivered to it for marketing or otherwise; and

WHEREAS, all prerequisite acts and proceedings preliminary to the adoption of this Resolution have been taken and done in due and proper form, time and manner; and

WHEREAS, the Board of Directors (the **Board**) of the Cooperative desires to take the necessary action to cause the Cooperative to borrow up to One Hundred Million Dollars ($100,000,000) from CoBank, ACB (**CoBank**) to be used to finance capital expenditures or for other general corporate purposes;

NOW, THEREFORE, BE IT RESOLVED, that the President, the CEO and General Manager, the Secretary, any Assistant Secretary, the Senior Vice President and CFO and any other officer of the Cooperative are jointly and severally authorized and empowered to obtain from CoBank, on behalf of the Cooperative, a loan (the **Loan**) in an aggregate principal amount not to exceed One Hundred Million Dollars ($100,000,000); and for such purposes:

(1) to execute such application or applications (including exhibits, amendments and/or supplements thereto) as may be required for all borrowings;

(2) to obligate the Company to pay such rate or rates of interest as the Officers so acting shall deem proper, and in connection therewith to purchase such interest rate risk management products as may be offered from time to time by CoBank;

(3) to obligate the Company to such other terms and conditions as the Officers so acting shall deem proper;

(4) to obligate the Company to make such investments in CoBank as required by CoBank;

(5) to execute and deliver to CoBank or its nominee all such written loan agreements, documents and instruments as may be required by CoBank in regard to or as evidence of any Loan made pursuant to the terms of this Resolution; in particular (a) a Loan Agreement with CoBank substantially in the form presented to this meeting (the **Loan Agreement**); and (b) a Promissory Note substantially in the form presented to this meeting in an aggregate principal amount not to exceed One Hundred Million Dollars ($100,000,000) with a term not to exceed thirty (30) years (the **Note**);

(6) to pledge, grant a security interest or lien in, or assign property of the Company or property of others on which it is entitled to borrow, of any kind and in any amount as security for any or all obligations (past, present and/or future) of the Company to CoBank;

(7) from time to time extend, amend, renew or refinance any such Loan;

(8) to reborrow from time to time, subject to the provisions of this Resolution, all or any part of the amounts repaid to CoBank on any Loan made pursuant hereto (whether for the same or a different purpose);

(9) to execute and deliver to CoBank an Electronic Commerce Master Service Agreement, a separate Service Agreement for each different service requested by the Company, and such other agreements, addenda, documents or instruments as may be required by CoBank in the event that the Company elects to use CoBank's electronic banking system (the **System**);

(10) to execute and deliver to CoBank any agreements, addenda, authorization forms and other documents or instruments as may be required by CoBank in the event that the Company elects to use any services or products related to the Loan that are offered by CoBank now or in the future, including without limitation an automated clearing house (ACH) service;

(11) to direct and delegate to designated employees of the Company the authority to direct, by written or telephonic instructions or electronically, if the Company has agreed to use the System for such purpose, the disposition of the proceeds of any Loan authorized herein or any property of the Company at any time held by CoBank; and

(12) to delegate to designated employees of the Company the authority to request by telephonic or written means or electronically, if the Company has agreed to use the System for such purpose, loan advances and/or other financial accommodations, and in connection therewith, to fix rates and agree to pay fees. In the absence of any direction or delegation authorized in (11) or (12) above, all existing directions and/or delegations shall remain in full force and effect and shall be applicable to any Loan authorized herein.

RESOLVED FURTHER, that each of the Officers are hereby jointly and severally authorized to:

(1) establish a Cash Investment Services Account at CoBank;

(2) make such investments therein as any Officer shall deem proper;

(3) direct by written or telephonic instructions or electronically, if the Company has agreed to use the System for such purposes, the disposition of the proceeds therein;

(4) delegate to designated employees of the Company the authority set forth in (2) and (3) above; and

(5) execute and deliver all documents and agreements necessary to carry out this authority.

RESOLVED FURTHER, that each of the Officers are hereby jointly and severally authorized and directed to do and/or cause to be done, from time to time, all things which may be necessary and/or proper for the carrying out of the terms of these Resolutions.

RESOLVED FURTHER, That the Board authorizes the Cooperative to take any and all steps which may be necessary or desirable to issue to CoBank, and execute and deliver the Note under and in accordance with the Amended and Restated Indenture dated as of May 5, 2015 between the Cooperative and U.S. Bank National Association, as trustee (the **Trustee**) as supplemented by the Supplemental Indenture (as defined below) (the **Indenture**) including making a request to the Trustee to authenticate the Note and making the necessary filings and certificates which must be filed with, or otherwise delivered to, the Trustee to support a request to the Trustee to authenticate the Notes as "Additional Obligations" under the Indenture. The Board hereby empowers, authorizes and directs each of the President, the CEO and General Manager, the Secretary, any Assistant Secretary, the Senior Vice President and CFO and the other proper Officers of the Cooperative, or their respective designees, to execute and deliver, on behalf of the Cooperative, all documents, instruments, certificates, agreements, indentures and other documents which may be necessary or desirable to complete the execution, authentication and delivery of the Note and the issuance thereof to CoBank. The authority conferred upon each of the President, the CEO and General Manager, the Secretary, any Assistant Secretary, the Senior Vice President and CFO, and such other officers of the Cooperative hereby specifically includes, but is not limited to the authority to execute, attest and deliver, or approve and accept, as the case may be, on behalf of the Cooperative, the Thirty-Fourth Supplemental Indenture to be dated as of a date not less than 90 days following execution of the Loan Agreement, substantially in the form presented to this meeting supplementing the Indenture with the Trustee and amending the Indenture (the **Supplemental and Amendatory Indenture**), with such changes, insertions and omissions as the person or persons executing or accepting the Supplemental and Amendatory Indenture may approve, the execution, approval or accepting the Supplemental and Amendatory Indenture being conclusive evidence of such approval by such person or persons.

RESOLVED FURTHER, That this Resolution constitutes a resolution as required by Section 4.1(A) of the Indenture authorizing and requesting the Trustee (i) to authenticate and deliver the Note (as "Additional Obligations" under the Indenture) under Sections 4.2, 4.3 and 4.5 and the other applicable provisions of the Indenture and (ii) to take such other steps as are required by the Indenture and/or the Loan Agreement to issue the Note.

RESOLVED FURTHER, that the President, the CEO and General Manager, the Secretary, any Assistant Secretary, the Senior Vice President and CFO and the other officers of the Cooperative are each hereby authorized and empowered to take such other action as might be required to complete the execution, authentication and delivery of the Note and the Cooperative's performance of its obligations thereunder and under the Loan Agreement.

RESOLVED FURTHER, That all prior acts by the Officers or other employees or agents of the Company to accomplish the purposes of these Resolutions are hereby approved and ratified.

RESOLVED FURTHER, That any Officer of the Company is hereby authorized and directed to cast the ballot of the Company in any and all proceedings in which the Company is entitled to vote for the selection of a member of CoBank's board of directors or for any other purpose.

RESOLVED FURTHER, That these Resolutions shall remain in full force and effect until a certified copy of a duly adopted resolution effecting a revocation or amendment, as the case may be, shall have been received by CoBank. The authority hereby granted shall apply with equal force and effect to the successors in office of the Officers herein named.

RESOLVED FURTHER, That the Secretary or any Assistant Secretary of the Company is hereby authorized and directed to certify to CoBank a copy of these Resolutions, the names and specimen signatures of the present Officers above referred to, and if and when any change is made in the personnel of any said Officers, the fact of such change and the name and specimen signatures of the new Officers.

CoBank shall be entitled to rely on any such certification until a new certification is actually received by CoBank.

B. Accounting Report

Darla Miller, Senior Accounting Analyst, reported that the February 2016 Statement of Operations reflected an estimated net margin of $2.1 million compared to $25.7 million last month and $13.6 million for the same period last year. The budgeted net margin for February was $9.2 million.

February sales to members were $105.3 million compared to $125.3 million last month and $109.4 million for the same period last year. February sales to members were budgeted to be $112.6 million. Member sales in MWh for February were 1,846,200 MWh.

Surplus sales were $11.3 million compared to $14.5 million last month and $15.8 million for the same period last year. Surplus sales were budgeted to be $18.7 million in February. Sales to DGC contributed $3.8 million. The sales to DGC reflect the new transfer pricing agreement with DGC effective January 1, 2016. Surplus sales in MWh for February were 636,400 MWh.

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

Basin Electric's February equity-to-asset ratio was 18.75% compared to 18.66% in January.

The February equity-to-capitalization ratio using Moody's Rating Service's methodology (both without the consolidation entry for Coteau) was 22.60% compared to 22.40% in January.

The February equity-to-capitalization ratio based on indenture requirements for patronage distribution was 21.17% compared to 21.09% in January.

C. 2015 Capital Credit Allocation

Shawn Deisz, Vice President & Controller, then reviewed the Cooperative's financial performance for 2015, noting that Basin Electric's allocable margin for the year is $49,407,771.51 and Basin Cooperative Services' allocable net deficit was $24,385.98 for a combined allocable margin of $49,383,385.53. She recommended that the Board allocate this margin.

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

R13.03-15-16 WHEREAS, for the fiscal year ended December 31, 2015, Basin Electric Power Cooperative (**Basin Electric**) realized a margin before income taxes of $49,407,771.51 and Basin Cooperative Services (**BCS**) realized a net deficit of $24,385.98 for a combined allocable margin of $49,383,385.53;

NOW THEREFORE, BE IT RESOLVED, that the 2015 Basin Electric before-income-tax margin and the 2015 BCS net deficit in the combined total of $49,383,385.53 be allocated to the patrons of Basin Electric on a patronage basis in accordance with the provisions of the Bylaws of Basin Electric Power Cooperative.

27. Board Cost-Cutting Measures

The board discussed possible measures it could take in support of the Cooperative's austerity program. Staff will provide the board with information concerning director expenses which can be discussed in greater detail at next month's board meeting. It was decided to hold the May Board meeting in Bismarck rather than traveling to the Great Plains Synfuels Plant.

28. Directors' Reports

Director Pearson thanked Mr. Sukut and staff for attending the East River Energy Forum.

Director Rohrer thanked staff for attending the Central Montana Electric Power Cooperative annual meeting.

Director Thiessen thanked staff for the in-depth reports he received this month.

Director Gilbert reported he attended the Corn Belt strategic planning session. He invited Mr. Sukut to attend Corn Belt's April 6, 2016 annual meeting.

Director Brekel invited staff to attend Tri-State's April 7, 2016 annual meeting. He attended the Midwest meeting and had a good discussion on the CPP.

Director Applegate invited staff to attend the April 5, 2016 Northwest Iowa Power Cooperative annual meeting.

Director Drost reported on a CPP meeting he attended sponsored by the Minnesota Pollution Control Agency.

Director Peltier noted the Minnesota Rural Electric Association (**MREA**) meeting is scheduled for March 22 & 23, 2016. Warren Rau is running for MREA director and he would appreciate our support.

29. Executive Session

At 11:30 a.m., it was moved by Director Presser, second by Director Pearson and carried that the Board retire into executive session to discuss negotiations with Tri-State. Director Brekel recused himself from executive session during the Tri-State discussions. At 11:40 a.m., it was moved by Director Baker, seconded by Director Drost and carried that the board arise from executive session.

30. Date and Time of Next Board Meeting

The next regularly scheduled meeting of the Board of Directors will take place April 12-14, 2016, at the headquarters building in Bismarck, North Dakota.

31. Adjournment

President Peltier adjourned the meeting at 11:41 a.m.

Gary C. Drost
Secretary-Treasurer