Approved June 13, 2017

Basin Electric Power Cooperative
Bismarck, North Dakota

Minutes of the Regular Meeting of the Board of Directors
May 9-11, 2017

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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, on May 9, 2017 starting at 8:00 a.m. CDT.

1. Call to Order

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

2. Roll Call

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

Donald E. Applegate	Paul Baker
Leo Brekel	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 and General Manager Paul M. Sukut and Basin Electric staff members Tracie Bettenhausen, Eric Carufel, Tammy DeWitt and Steve Johnson; Corn Belt Power Cooperative (**Corn Belt**) directors Jerry Beck, Ron Deiber, Donald Feldman, Terry Finley, David Onken, Larry Rohach, Dale Schaefer and Scott Stecher; Corn Belt executive vice president and general manager Kenneth Kuyper, Corn Belt senior vice president-finance and administration Karen Berte; and Prairie Energy Cooperative (**Prairie Energy**) general manager Becky Bradburn.

3. Meeting with Corn Belt Power Cooperative Board of Directors

Following introductions of the Corn Belt and Basin Electric directors and staff, the Corn Belt directors expressed their concerns, primarily about how Basin Electric deals with excess margins.

Corn Belt senior vice president-finance and administration Karen Berte then made a presentation with respect to Corn Belt's view of alternatives for the handling of higher margins collected from current members. The list of possible alternative strategies included (a) rate reduction/bill credit; (b) patronage allocation and first-in/first-out retirement; and (c) patronage allocation and a combination of last-in/first-out and first-in/first-out retirement. Ms. Berte then went on to discuss the pros and cons of each alternative.

4. Recess and Reconvention

At 8:50 a.m., President Peltier recessed the meeting and directed the Board committees to meet. President Peltier reconvened the meeting at 3:00 p.m.

5. 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, Tammy DeWitt, Matthew Greek, John Jacobs, Dan Job, Steve Johnson, Kerry Kaseman, Becky Kern, Janet Kubisiak, Dale Niezwaag, Diane Paul, Mike Paul, Dave Raatz, Mike Risan, Ken Rutter, Susan Sorensen, Myron Steckler, Kevin Tschosik, Valerie Weigel, Michelle Wiedrich and Tiffany Zablotney.

Also present were Dakota Gasification Company (**DGC**) Vice President David J. Sauer and Prairie Energy general manager Becky Bradburn.

6. 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 Brekel and carried that the agenda be approved as modified.

7. Board Committee Reports

Finance Committee. Director Brekel reported that the Finance Committee received a report from Diane Paul on the proposed changes to the Cooperative's Section 401(k) Plan that will be presented to the full board for action in June. The changes (1) would allow immediate employee 401(k) contributions for non-union employees, (2) allow employees to convert previous contributions to a Roth IRA; and (3) have a third-party review of the plan and investments. Ms. Paul also reported on bids for the medical and dental plans. The group spent more than an hour with Alan Spen from the Aspen Group discussing Basin Electric's credit. Mr. Spen will meet with the full Board tomorrow. The Finance Committee also attended a portion of the Planning, Resource & Marketing Committee meeting.

Operations Committee. Director Applegate reported that the Operations Committee received a presentation on the coal mine, mining operations, problems blending coal and facts and figures for each plant--Antelope Valley Station (**AVS**), Leland Olds Station (**LOS**) and the Great Plains Synfuels Plant.

Planning, Marketing & Asset Management Committee. Director Gilbert reported that Dave Raatz discussed contract term pricing. Mike Risan discussed negotiations on formation of the Mountain West Transmission Group (**MWTG**). Valerie Weigel discussed marketing.

8. Approval of the Minutes

The minutes of the April 11-12, 2017 Regular Meeting of the Board of Directors were presented and after an opportunity for corrections, it was moved by Director McQuistion, seconded by Director Presser and carried that the minutes be approved as presented.

9. General Manager's Report

General Manager Sukut and Director Baker reported that the Western Fuels Association (**Western Fuels**) board continues work to determine a more equitable rate structure. The board is also looking at equaling out the number of board members for each member. The Western Fuels board decided to hold six in-person meetings and two videoconference meetings per year. Mr. Sukut reported that Charles Ayers from Sunflower Electric Power Corporation has retired from Western Fuels board, Tony Casado from Tri-State Generation & Transmission Association, Inc. (**Tri-State**) will retire in August and Don Gray from Kansas City Board of Public Utilities also plans to retire.

10. Office of General Counsel Report

Senior Vice President & General Counsel Mark D. Foss reported on the status of litigation involving the Cooperative. He noted that on March 30, 2017, the Environmental Protection Agency (**EPA**) agreed to conclude the LRS Section 114(a) information request via an administrative settlement rather than a consent decree.

He reported that the LRS Best Available Retrofit Technology (**BART**) settlement was signed by EPA Administrator Scott Pruitt on April 24, 2017. We will now begin the state administrative process in Wyoming to get a revised State Implementation Plan approved to accommodate the settlement.

A. Board Policies

Mr. Foss distributed Board Policy #07, Guiding Principles for (Business) Diversification, showing the revisions proposed by the internal committee and asked that the Directors review prior to the June meeting when he would request approval.

11. Operations Report

Senior Vice President - Operations John Jacobs reported there were two medical treatments and one Days Away, Restricted or Transferred (**DART**) incident during the month. The DART occurred at LOS, ending its 10-year run without a DART.

April generation was 1,826,008 MWh compared to budgeted generation of 1,852,870 MWh which is 1.4 percent below the budget. He reviewed forced-outage rate trends for the last 24 months and provided April 2017 bus-bar costs for the coal-fired fleet LOS, AVS, Laramie River Station (**LRS**) and the Dry Fork Station (**DFS**)). Year-to-date generation for the solid-fuel plants is 9.4 percent below budget and for the total fleet is 1.4 percent under budget. April operating statistics were as follows:

Unit	Monthly Availability	Running Plant Capacity Factor (net)	Unit Rating	Comments
AVS #1	46%	93%	450 MW	Scheduled outage 4/15-30/17.
AVS #2	100%	90.3%	450 MW	Feedwater heater.
DFS	100%	99.43%	386 MW	

LRS #1	98.85%	60.80%	570 MW	Forced outage on 4/4/17 for auxiliary transformer high-phase differential.
LRS #2	100%	78.26%	570 MW	
LRS #3	23%	70%	570 MW	Scheduled outage 4/8-30/17.
LOS #1	100%	79.71%	221 MW	Going into major outage this fall. Toward end of run and some decisions regarding decreasing capital costs are catching up with us.
LOS #2	100%	79.67%	448 MW	

Mr. Jacobs presented a three-dimensional graphic portraying what the Integrated Test Center (ITC) will look like after completion and noted that XPrize has narrowed its number of remaining contestants to 12 and is expected to name the top five in November or December.

The United States Corps of Engineers has informed LOS that it plans to curtail all releases from Garrison Dam for a six-hour period so boat ramp maintenance can be performed. LOS staff will need to monitor its water intake facility on the Missouri River to assure the water level remains above the intake structure during this period of time.

12. Engineering & Construction Report

A. Headquarters Building Expansion Update

Structural Engineering Supervisor Chris Bauer reported there were three on-site safety incidents since the last Board update.

Major milestones include completion of all building structural work, the new roof is weather-tight, site utility and paving work is underway, new cooling tower is operational, layouts of the office furniture for the new addition are complete (minor changes were needed with the reorganization) and the design team is working on detailed furniture and wall layouts in the existing building addition.

He noted that the warehouse/shop building is occupied. Final project closeout is expected by the end of June.

Mr. Bauer reviewed the schedule for site work and completion of each floor and the atrium, furniture installation and employee relocation, as well as remodel of the existing building.

He then reviewed the amounts approved, amounts spent to date and projected final costs for the east blunt remodel, warehouse/shop and west addition. The directors then toured the west building addition.

13. Recess and Reconvention

At 4:05 p.m., President Peltier recessed the meeting until 8:00 a.m. May 10, 2017, at which time the meeting reconvened with President Peltier continuing to preside and Secretary Gary C. Drost keeping the minutes.

14. 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, Shawn Deisz, Tammy DeWitt, Matthew Greek, John Jacobs, Steve Johnson, Becky Kern, Janet Kubisiak, Darla Miller, Kimberly Miller, Dale Niezwaag, Diane Paul, Mike Paul, Dave Raatz, Chad Reisenauer, Mike Risan, Ken Rutter, Chris Schmidt, Garrett Schilling, Matthew Simon, Susan Sorensen, Myron Steckler, Maria Tomac, Kevin Tschosik, Valerie Weigel, Michelle Wiedrich, Roxanne Woeste and Tiffany Zablotney. Also present were DGC Vice President David J. Sauer and Prairie Energy general manager Becky Bradburn.

15. Financial Services Report

A. Review of Basin Electric's Credit Rating Strategy by Alan Spen

Mr. Johnson introduced Alan Spen, who worked with S&P Global Ratings and later at Fitch Ratings, Inc. Mr. Spen, now President of Aspen Ratings Group, LLC, reported that earlier this year he was contacted by Basin Electric about doing an independent analysis of the Basin Electric credit, with the goal of providing senior management and the Board of Directors ideas on how best to stabilize the Basin Electric credit ratings and help develop a long-term strategy that would support an 'A'/'A2' Stable Outlook credit rating.

It was Mr. Spen's belief, that as a part of a self-evaluation, the Cooperative needs to consider all reasonable options to place the Cooperative on a more secure and stable financial foundation. While previously considered a neutral factor, DGC is now considered a negative counterweight to the generally successful performance of Basin Electric's electric operations. Developing a comprehensive Board policy that better balances the pluses and minuses of these two businesses will be central to Basin Electric's ability to achieve higher credit ratings.

Mr. Spen then reviewed his findings, including a current evaluation of Basin Electric and its key credit factors, ideas regarding possible financial enhancements to mitigate credit rating volatility, a comparison between Basin Electric and Tri-State using the Moody's methodology and his conclusions and recommendations.

16. Operations Report, continued

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 Generating Station (**PGS**) and

Lonesome Creek Station (**LCS**)) were steady from the previous month. April generation at the distributed generation facilities, the combustion turbines (**CT**) and the reciprocating engines (**RE**) was as follows:

Unit	Run Hours	Cpcty Factor (%)	Avg Gen (MW)	Avail (%)	Unit Rate (MW)	Comments
Culbertson CT	109.25	4.66	29.80	99.75	97	
LCS CT #1	177.87	15.23	27.73	96.08	45	Ran for load demand and reliability.
LCS CT #2	404.07	38.22	30.65	93.01	45	Ran for load demand and reliability.
LCS CT #3	0	0	0	0	45	Down for maintenance. To Calgary and engine torn down and we're on schedule to get back 6/2/17. Other issues will be repaired. Five other engines in shop with same issue this turbine had. Lot of staff is former GE employees.
PGS CT #1	126.5	10.43	26.71	98.77	45	Boroscope conducted; no issues on #1.
PGS CT #2	97.63	8.35	27.71	99.07	45	Preliminary report, seeing issue with compressor oil manifold on #2. Will watch it closely. #2 has about 6,000 hours.
PGS CT #3	89.37	7.23	26.21	98.73	45	Borocope conducted; no issues on #3.
PGC RE #11	190.85	12.81	4.50	98.68	111.6	
PGC RE #12	180.58	11.47	4.25	98.71	111.6	

PGC RE #13	193.72	13.25	4.58	98.7	111.6	
PGC RE #14	193.27	13.58	4.70	98.78	111.6	
PGC RE #15	194.58	13.68	4.71	98.58	111.6	
PGC RE #16	185.98	12.80	4.61	97.97	111.6	
PGC RE #17	196.03	13.53	4.62	99.03	111.6	
PGC RE #18	184.28	12.53	4.55	95.28	111.6	
PGC RE #19	196.22	13.58	4.63	98.85	111.6	
PGC RE #20	205.6	14.26	4.64	98.94	111.6	
PGC RE #21	192.47	13.08	4.55	86.22	111.6	
PGC RE #22	201.92	13.83	4.59	99.03	111.6	
DCS	161	11.67	156.63	71.77	300	6-day outage. Ran for load demand.
Groton #1	19.88	1.21	41.75	83.75	95	Ran for load demand. Took down for 4 days to replace RTU in switchyard for both units.
Groton #2	178.65	7.92	30.31	92.43	95	Ran for load demand.
SMS #1	0	0	0	0	120	Did not run.
SMS #2	0	0	0	0	120	Did not run.
WDG				100	54	

<u>LCS #3 Repair Update</u>. Mr. Tschosik reported he visited the TransCanada shop in Calgary where the LCS #3 CT is being repaired. He reported that work outlined in three General Electric (**GE**) service bulletins is also being done while the CT is in the shop. TransCanada is on schedule to return the turbine by June 2, 2017. There were five other engines in that shop with the same issue as our turbine. Many TransCanada employees are former GE employees. He noted that it was a nice, clean shop. Staff is seeing some of the same problems on the LCS #2 CT, so it may also be removed and repaired. A more detailed report on the LCS #3 repair will be presented in June. TransCanada reported that it has repaired a couple dozen GE CTs for this same issue. Mr. Tschosik stressed that we need to be very careful to comply with the recommended work to be performed after a set number of hours of operation or be exposed to a higher risk of failure.

In response to a question, Mr. Tschosik reported that LCS #4 and #5 had still not been declared in commercial operation. Mr. Risan reported on the status of agreements with McKenzie Electric Cooperative, Inc. (**McKenzie**).

Mr. Tschosik reported that the DCS scheduled spring outage took place April 22-28 and included inspection of the engine, heat recovery steam generator (**HRSG**) and air-cooled condenser wash. He presented photographs and discussed the HRSG building work. He noted that the unit will be boroscoped soon and again in the fall to determine if repairs are needed to the hot gas path. Such an outage would cost $10 million. Final closeout will take place June 10 or so. The only work that remains is some on-site grading and upgrading some drawings. This project is under budget.

Director Drost reported that Sioux Valley Energy (**Sioux Valley**) held its last board meeting at DCS. The DCS staff was knowledgeable and the Sioux Valley board appreciated their hospitality.

During April, LCS ran in synchronous condensing mode for 464.70 hours and PGS for 568.85 hours. There were six west-side spinning reserve calls during the month.

The east-side peak for wind occurred on April 15 2017 at 1500 hours. At that time, wind generation was as follows:

Wind Project	**Load Factor during the Peak**	**Average Capacity Factor**		**Project Total**
		Month	**2017**	
Baldwin	99 MW	37%	45%	99 MW
Brady #1	133 MW	42%	53%	150 MW
Brady #2	48 MW	36%	48%	150 MW
Campbell County	89 MW	43%	47%	98 MW
Chamberlain/Pipestone	1 MW	26%	25%	3.4 MW
Day County	85 MW	50%	49%	99 MW
Edgeley	27 MW	27%	32%	40 MW
Highmore	26 MW	35%	36%	40 MW
Iowa	12 MW	41%	43%	45.1 MW
Iowa Lakes	5 MW	44%	47%	21 MW
Minot Wind (2 Nordex turbines)	4 MW	27%	32%	7.1 MW
PWND (GE turbines)	112 MW	38%	47%	115.5 MW
PWSD	63 MW	43%	48%	162 MW
Sunflower	99 MW	41%	51%	104 MW

Wilton	91 MW	36%	39%	99 MW
Total Monthly Wind Generation	889 MW			800 MW
Average Capacity Factor		39%	47%	

On April 23, 2017, a snowstorm caused a Western Area Power Administration (**Western**) 230-kV line to go down, resulting in an outage at PWND and a loss of 690 MW. Repairs were completed on 29 wind turbine generator gearboxes. Annual maintenance is 19 percent complete.

On April 10, 2017, a snowstorm caused a Western 230-kV line to go down, resulting in a 15-minute outage at PWSD. Semi-annual maintenance at PWSD is five percent complete.

Mr. Tschosik reported that the 150 MW Lindahl Wind Project will be added to these statistics.

B. Leland Olds Station Update

LOS Plant Manager Jamey Backus reported that there was a DART incident at LOS on April 25. Prior to that incident, the LOS employees had worked 3,321,493 man-hours without a DART incident (since October 24, 2006). A meeting on the hazards and challenges specific to their classification was held with the coalmen. The results of the safety perception survey were discussed with all employees.

Year-to-date, LOS has produced 89.2 percent of budgeted generation, with Unit #1 at 80 percent of budgeted generation, 87 percent availability and 80.4 percent running plant capacity factor (**RPCF**) and Unit #2 at 94.3 percent of budgeted generation, 94.2 percent availability and 81.3 percent RPCF.

The year-to-date Unit #1 outages have been for wall tube leaks, reserve shutdown and an eight-day outage to repair a primary superheat leak. The year-to-date Unit #2 outages have been for galloping lines due to high winds and a seven-day outage to deslag the boiler and for reserve shutdown. Mr. Backus presented photographs and discussed the Unit #1 primary super heater outage. Derates were taken for boiler cleaning, selective non-catalytic reduction testing, optimizer testing, fly ash system issues, high sulfur coal and to install new Unit #2 batteries. The Unit #1 optimizer has been integrated into the distributed control system. The optimizer receives and uses feedback from the ZOLO system to control individual burners at the same time. This supports NO_x control.

The east plant entrance road has been closed so soil borings can be done and ground stabilization work can begin for the bottom ash-dewatering project.

As of May 1, 2017, the LOS coal inventory was 516,897 tons of lignite and 91,822 tons of Powder River Basin (**PRB**) coal, compared to the May 1, 2014 coal inventory of 411,737 tons of lignite and 84,791 tons of PRB coal.

C. LOS Solid Waste Landfill Phase 6 - Amendment

Mr. Backus reported that in 2012, a capital project request (**CPR**) was made and approved to permit and construct a new landfill, which would allow continued operation of LOS. The value of the CPR was based on construction costs of new cells at the time and estimated costs of engineering and permitting. The original timeline for building the new landfill was based on known fly ash quantities and estimated gypsum production from the scrubber.

In April 2015, the EPA released the draft Coal Combustion Residue (**CCR**) Rule and in October 2015, the final CCR rule was issued. As a result, LOS stopped sluicing bottom ash to the ash ponds and began placing dry bottom ash in the existing landfill, which now constitutes one-third of the landfill waste. The final CCR significantly changed how solid waste landfills are designed, permitted and built.

In February 2016, AECOM was awarded the contract for engineering, permitting assistance and design of the new landfill at an approximate cost of $641,000.

The new rule required additional monitoring wells to be installed at an approximate cost of $285,000. The new landfill liner requirements include a compacted clay liner, a leachate collection system and a 60-mil high-density polyethylene liner. The previous landfill liner requirements included only the compacted clay liner.

Design and permitting documents for the new landfill were completed in March 2017. The landfill will be developed in eight segments, starting with the construction of Cells 1A and 1B. Each subsequent set of cells will be needed approximately every three years.

AECOM developed an estimated construction cost for Cells 1A and 1B based on the design and quantities. Headquarters Engineering used the AECOM design and quantities to develop a Class 2 overall project cost estimate. The two construction cost estimates were very similar, showing the cost of construction would be over $6.2 million. Based on previous cost data, the overall project cost was estimated at that point to be $7.2 million.

Mr. Backus presented photographs and discussed the existing landfill and diagrams of Landfill Phase 6 and Phase 6 Cells 1A/1B. He estimated this would provide from five to six years of landfill space.

He reported that construction bids for Cells 1A/1B of the new landfill were received on May 4. The low bids came in under $4 million, assuming a start date of June 1, 2017. Estimates were based on actual costs for other landfill developments over the last 10 years. Due to the size of this project, the bidders offered a significantly lower cost.

This is the first new landfill Basin Electric has had to design and permit under the new CCR Rule. All future landfill cells and expansions will be subject to these rules. Design and construction of a new landfill under the CCR Rule is much more costly than in the past.

Mr. Backus reviewed the overall project schedule and noted that construction is scheduled from June 2017 through January 2018. He reviewed the cost summary for a total project cost of $5,952,136 and recommended the resolution be adopted to increase the authorized dollar amount of the CPR.

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

R01.05-09-17 RESOLVED, that Capital Project Request #150218 to construct Cells 1A and 1B of the LOS Landfill Phase #6 be amended from $1,088,719 to $5,952,136; and

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

D. Award of LOS Solid Waste Landfill Phase 6 Cells 1A/1B Construction Contract

Mr. Backus reported that the low evaluated bidder for this work was Northern Improvement Company (**Northern Improvement**) at $3,74,883.80 (the two bids on either side of the Northern Improvement bid were not complete). There were six bidders and bids were based on a not-to-exceed price based upon the scope of work.

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

R02.05-09-17 RESOLVED, that construction contract for LOS Landfill Phase 6 - Cells 1A/1B be awarded to Northern Improvement Company for $3,774,883.80; and

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

17. Risk Management Report

Senior Commodity Risk Analyst Tiffany Zablotney reported on Basin Electric's current hedge position based upon the combined strategy of east purchase power and natural gas burn. For 2017, the remainder of the year is hedged 35 percent at an average natural gas price of $2.96 per dekatherm (**dkt**). The power price is physically hedged at $20.48 per Megawatt hour (**MWh**) on-peak and $9.70/MWh off-peak.

Purchase power hedging is not built into the strategy in the outer years due to a lack of market liquidity. For 2018 natural gas, the current hedged position is $2.97/dkt with 70 percent hedged. Years 2019-2021 are hedged at an average price of $3.20/dkt and have been hedged, in general, up to the maximum hedge limits approved by the Risk Management Steering Committee (**RMSC**).

She reviewed the open basis position to Ventura and the hedges executed at the Henry Hub indexed price where the basis to Ventura hedge has not yet been executed. She reviewed the new basis hedges executed last month for June of 2018 and December of 2019. Marketing is required to execute the Ventura basis hedge within four months of the trade's settlement date.

The Ventura Forward price curve increased for the second month in a row to a 2017 average price of $3.16/dkt, which is an increase of $0.07/dkt. The outer years of the curve had an overall average increase of $0.11/dkt as of May 1.

Applying the Ventura curve to the natural gas hedges executed, Basin Electric has an unrealized Mark-to-Market (**MTM**) loss of ($4.3 million). This is a month-over-month positive change of $3.5 million from last month.

Ms. Zablotney reviewed the on-peak power hedges for a combined average price of $28.51/MWh for 2017 and $25.75/MWh for 2018. The Off-Peak hedges have an average price of $22.42/MWh for 2017 and $19.50/MWh for 2018. A complete Basin Electric hedge plan beyond 2017 has not yet been approved by the RMSC; however, there was a specific trade for 25 MWs around the clock that was approved in the interim.

The Cooperative's surplus sales hedges on the West are indexed to Palo Verde. Prices for on-peak increased again for 2017 by $2.64/MWh for an annual average of $31.62/MWh. The off-peak curve again had similar movement in prices across the curve.

Applying the Palo Verde forward curve to the current executed power hedges, the Cooperative has an unrealized MTM gain of $290,000 as of April 30th. This does not include the two long-term physical contracts with Cargill Power (**Cargill**) having a ($50.2 million) unrealized MTM loss.

The hedge position of diesel is unchanged from last month. About 46 percent of the forecast for 2017 is hedged at an average price of $2.43/gallon (**gal**) and about 36 percent is hedged for 2018 at an average price of $2.56/gal.

The financial hedges for the Cooperative's diesel are executed against the Energy Information Agency On-Highway Diesel Index. Diesel prices dropped slightly again by about $0.08/gal to $2.54/gal on average for 2017.

Applying the forward curve to the executed hedges, the Cooperative had an unrealized MTM gain of $92,000 on its diesel hedges. The month-over-month MTM dropped $100,000.

Settlements in April resulted in cash receipts of $157,000 for power (50 MWs) and $8,000 for diesel (84,000 gallons). There were no natural gas hedges settled for April. Overall, Basin Electric has received $1.4 million year-to-date for financial hedge settlements.

Combining the MTM value for all commodities as of April 30, Basin Electric had a net unrealized loss on physical and financial transactions of ($3.9 million), excluding the two long-term Cargill purchase power contracts.

She also reviewed the Cooperative's liquidity position for each counterparty with whom Basin Electric has an executed margin agreement. In response to a Board request last month, Ms. Zablotney reported that Basin Electric's greatest liquidity exposure is with Cargill at $50.2 million. Cargill has contractually extended Basin Electric a $15 million margin limit plus an additional $2 million internal threshold beyond the contractual amount. The majority of the exposure is marked against the Mid-C Index with a basis adjustment to Montana. As of May 1, Basin Electric had a posted cash margin of $33.2 million with Cargill.

The credit exposure position reviewed is based on Basin Electric's internal ratings model with the greatest exposure to entities rated "A" or better.

18. Marketing & Asset Management Report

Director of Marketing and Financial Analytics Valerie Weigel reviewed the North Hub, Minnesota Hub and Palo Verde Hub 2018 pricing, noting that generation from solar and wind resources is expected to displace 1.6 billion cubic feet per day (**bcf/d**) of power burn demand this summer. Solar and wind capacity in the United States is expected to grow by 7.3 GW and 3.8 GW, respectively, from April through October of 2017. The Southwest Power Pool (**SPP**) has installed three to four GW of wind per year the last couple years.

So far this year, SPP has installed 750 MW and expects 10,000 to 15,000 MW by years-end.

She reviewed a chart of April SPP Wind-to-Load Penetration Levels and noted that overall monthly wind-to-load penetration was 30 percent. Last year it was 22 percent.

The transacted purchase price for April day-ahead load-zone pricing was $19.29 compared to the budget of $18.38. The transacted sale price was $18.35 compared to the budget of $18.38 which is slightly lower than last April. Gas prices were over $1 higher than last year, which helped to prop this up.

Basin Electric saw the April hourly volumetric position fluctuate due to AVS #1 being offline from April 15-30.

The 2017 year-to-date Basin Electric natural gas burn was 3.1 million mmbtu compared to the budget of 420,000 mmbtu due to LCS reliability runs, changes in natural gas and power changes from the time of budget and underlying dispatch model assumptions. Impacts are difficult to hedge due to unforeseen positions and the variances in natural gas expense, purchase power expense and surplus sales expense.

With respect to generator revenue and expenses, Ms. Weigel explained how the market sees the unit with respect to short-term market-related profit and loss, how Basin Electric should think about unit offers and operation with respect to actual short-term profit and loss and what kind of resources should Basin Electric retain, build or purchase in the future regarding long-term decision-making.

She ranked the generators from best to worst performing, given market prices using the short-term perspective (e.g. no fixed costs): DCS, AVS #1, LCS #1, LOS #1, LRS #1, Brady #1, Young #1 and Day County.

She compared that to the ranking of the generators from best to worst performing, given market prices using the long-term perspective (e.g. with fixed costs): LRS #1, AVS #1, Brady #1, Young #1, LCS #1, LOS #1, DCS and Day County. Fixed costs were based on 2016 fixed costs and 2016 MWh output.

SPP April Highlights. We enjoyed a $2.8 million favorable variance in SPP for the month. The average sales price was $18.35/MWh versus the budget of $18.68/MWh. The average purchase price was $19.29/MWh versus the budget of $18.38/MWh. For the first time, day-ahead congestion hedging did not cover the full amount of day-ahead congestion. Actual wind output was lower than budgeted, which provided favorable results.

West April Highlights. We enjoyed a $0.5 million favorable variance in the west for the month. Counterparty west-side outages propped up sales prices for April while purchase prices were kept low with surplus hydropower which provided some arbitrage-related opportunities. The average purchase price was $7.10/MWh. The average sales price was $21.28/MWh versus the budget of $20.52/MWh.

MISO April Highlights. We had a $0.3 million unfavorable variance for the month in Midwest Independent System Operator (**MISO**). The average sales price was $23.08 versus the budget of $22.26. Walter Scott #4 and the Neal Station were in economic outage most of April.

Annual Congestion Auction. Ms. Weigel reported that the congestion-hedging year runs from June through May. The April 16 through March 17 day-ahead congestion expense was $8.2 million and the June 16 through March 17 congestion-hedging revenue was $13.1 million, resulting in a net congestion (net of Auction Revenue Rights (**ARR**) and Transmission Congestion Rights (**TCR**)) revenue of $4.9 million.

SPP updates its annual congestion models every couple months. Updates to the transmission system in the Bakken area were not fully captured, which impacted the ARR allocation. Marketing & Asset Management staff is currently working with the Transmission Department to have the SPP models updated. Basin Electric still retains the opportunity to pick up additional allocations in monthly auctions.

Marketing is looking to purchase ARRs and TCRs for June and the remainder of the year for LRS. She anticipates getting more allocations with the corrected transmission model.

April Congestion Impact. A forced transmission outage on the Belfield-to-Charlie Creek line and a planned outage on the Hebron-to-Mandan line created Lewis and Clark and Dickinson transformer constraints. This resulted in higher negative congestion in the load zone than at the generators (AVS and LOS). In addition, very high negative congestion was experienced on the Miles City DC Tie and at the Brady and Sunflower wind farms.

April was the first month where day-ahead hedging products did not cover the day-ahead congestion. The ARR/TCR allocation was a bit lower in April. Basin Electric had 65 percent of its nomination cap on peak and 85 percent of our nomination cap off peak. The rolling 12-month allocation average is 81 percent in the on peak and 85 percent in the off peak. While allocation drives some of the net loss on the day-ahead congestion, in April it was more related to transmission line outages and related constraints. The cost to the Cooperative was approximately $300,000.

19. Resource Planning Report

A. Margin Level/Distribution Discussion

Margins/Rates/Patronage Discussion. Senior Vice President of Resource Planning Dave Raatz reported that discussions with the members, Rate Subcommittee and Managers Advisory Committee (**MAC**) had resulted in the following suggestions: (1) establish consolidated margin ranges based on financial metrics by covering DGC's losses and "excess" distribution; (2) revenue deferral should be the first objective with $50 million versus $75 million discussion; (3) going forward, consider bill credits versus lowering rates; and (4) discussion on risks of DGC, generation mix and commodities.

B. Managers Advisory Committee 2018 Rate Recommendations

Contract Term Pricing. Mr. Raatz reported that it was the recommendation of the Rate Subcommittee and MAC that members with 2050 contract terms (Tri-State, Wright-Hennepin Cooperative Electric Association and Minnesota Valley Electric Cooperative) be given the benefit of extended depreciation through 2050 because those members are still paying their proportionate share of the asset over the term of their wholesale power contract. This provides an annual value to the 2050 contract holders because they pay over a longer depreciation period, but they still pay for the entire cost of those assets over the course of their contract. This will decrease their costs in the early years, but increase their costs in the later years. Over the last year, we've been visiting pros and cons with members and, ultimately, both Rate Subcommittee and MAC recommended that 2050 contract term members be given the benefit of extended depreciation out to 2050.

Contract Term 2045-2050 Capital Addition Depreciation Treatment for 2050 versus 2075 term contracts. Under normal situations, for a capital addition made in 2020, the cost of that capital addition would be charged over the assets remaining depreciable life; however, as you get to the end of an asset's life (the last six years), you would normally minimize long-term capital investments in the asset. As a result, for 2050-2075 contract holders, a different capital investment strategy may be appropriate during the 2045-2050 time period. It was the recommendation of the Rate Subcommittee and MAC that capital additions during the period of 2045-2050 on the coal and gas assets that were on the books as of December 31, 2015, be extended over the expected remaining life of the asset (just the capital additions), treating all members comparable.

Contract Term Rate Calculation Methodology. When the 2016 and 2017 rate calculations were being made, we didn't know for sure which members would extend their contracts to 2075, so the rate calculation had to be flexible and transitional. As a result, the 2016 and 2017 rate schedules were written to charge members an initial standard rate and provided for a contract extension credit for those members that extended their contracts to 2075. If every member extended its contract to 2075, Basin Electric would have collected the right amount of dollars. But if all members didn't extend their contract term to 2075, Basin Electric would collect more dollars than required. As a result, we wrote these rate schedules to allocate the over-collected dollars to the 2075 contract term members at the end of the year.

Since we now know which members have not extended through 2075, we can do a rate calculation that truly reflects the appropriate rates for each individual member. The concept, which was endorsed by the Rate Subcommittee and the MAC, is that we calculate what those rate components would be if all members had 2050 term contracts and apply those rate components to the three 2050-term members. Then calculate the net rate components for the 2075-term members and eliminate the need for a year-end true-up.

Following discussions, Directors Drost and Pearson noted that with such a strong MAC consensus, the Board of Directors should direct staff to continue with these concepts. Director Peltier noted that since most of the directors and senior staff won't be here in 2050, this must be documented and written very clearly. Mr. Raatz noted that he's been asked to include the logic for the different rates for 2050-term and 2075-term members in the rate schedule. A final vote on the 2018 Rate Schedule will be presented in August.

It was also stressed that a policy needs to be in place to address how to charge one or all of the 2050 contract term members should they decide to extend their contracts at a later date.

20. Recess and Reconvention

At 12:00 noon, 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 keeping the minutes.

21. 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, Andrea Blowers, Eric Carufel, Tammy DeWitt, Tracy McBride, Darla Miller, Mary Miller, Dale Niezwaag, Diane Paul, Mike Paul, Curt Pearson, Nicole Perrault, Shawna Piatz, Dave Raatz, Mike Risan, Garrett Schilling, Susan Sorensen, Valerie Weigel and Michelle Wiedrich. Also present were DGC Vice President David J. Sauer and Prairie Energy general manager Becky Bradburn.

22. Resource Planning Report, continued

A. Managers Advisory Committee 2018 Rate Recommendations, continued

Contract Term Pricing, continued. Following a motion by Director Drost that was seconded by Director Pearson and carried, the following resolution was adopted, with Director Gilbert voting no:

R03.05-09-17 RESOLVED, that the Board of Directors directs staff to: (a) continue to develop separate rate components for Class A members with wholesale power contracts expiring in the years 2050 and 2075 to be approved as part of the 2018 Rate Schedule, as well as (b) draft a proposed Board Policy with respect to how rate components will be calculated if a member with a wholesale power contract term of 2050 extends its wholesale power contract term, for review and approval of the Board of Directors.

Demand Period Waiver. Mr. Raatz reported that staff is recommending an expansion of the current demand period waiver periods. The value of doing this is to give the members options to expand their off-peak marketing programs and to increase load management opportunities, both of which will reduce Basin Electric's resource expansion requirement. This expansion was unanimously recommended by the MAC.

Purchase Power Rate. To streamline the purchase rate structures, staff is recommending combining the Distributed Generation and Consumer Energy Purchase Rate into one purchase rate. This combined new rate would be at an average on-peak and off-peak rate established in the rate schedule for the whole system. The final prices would be updated in conjunction with the financial forecast. The other recommendation from staff would be to close the Renewable Resource Pass Through Rate to new applications in 2018.

Electric Heat Rate. There has been a great deal of discussion with the membership on the electric heat rate and there is consistent support that it be continued. If the electric heat rate were terminated, over time, Basin Electric would probably lose all electric heat sales and water-heating load as well.

The electric heat rate levels are currently set four mills higher than the Cooperative's average production cost, which is determined by the cost of owned and purchased power. Both the MAC and Rate Subcommittee endorsed Basin Electric's current electric heat rate-setting methodology. This rate will be offered with a one-year commitment and with the intent to continue it for five years. There were also discussions on load management restrictions of the rate. Members are looking at methods to reduce demand purchases from Basin Electric, which are currently at a rate of approximately $20/kW-month under the Electric Heat rate. Basin Electric provides a demand credit of 65% load factor on the associated energy. If electric heat is controlled at the time of the member's normal billing peak and the member also gets 65% demand credit, there would be a double dipping. Following considerable discussion with the Rate Subcommittee and MAC, it was recommended that the electric heat rate language be modified to only limit load management operations that directly communicate with the member consumers, such as: positive load control, time-of-use rates outside the demand period waiver period and direct consumer Facebook messaging, text messaging, demand controllers and time clocks. However, it would be acceptable for a member to issue non-direct consumer alerts, posts to the Member's webpage, or posting on its own Facebook page.

Interruptible Rate. Historically, Basin Electric allowed partial control under the Interruptible Rate, but several years ago we moved to require 100% control of load under this rate. The membership has requested that Basin Electric consider allowing partial control of loads under the Interruptible Rate. Staff believes, as we now require time registration demand meters on all qualifying loads, that we can allow partial control of loads by establishing a value for the residual load for each qualifying load.

Another new concept that has been requested is that if "accreditation" is available in a Regional Transmission Organization (**RTO**) environment, in lieu of member control at the time of the member peak. To implement, staff would want to limit the RTO option to generation control situations. Another requirement is that the RTO would be allowed to directly control generators. Under this concept, we would waive Base Rate Demand Billing on the lesser of 65% of the amount of "accreditation" or the load level at the time of Basin Electric's billing peak.

He noted there is general support of this concept and, with the Board's concurrence, staff would develop rate schedules with these different positions.

Standby Rate. We've contracted with Guernsey to assist with the development of a standby rate. We hope to have that by the end of May or early June, when it would be brought to the Board for discussion and ultimate approval in August.

B. Rate Subcommittee Long-Term Rate Strategy

Due to inclement weather, we couldn't get the entire Rate Subcommittee together in person to start the Long-Term Rate Strategy discussions.

C. RFP Mid-Term Recommendation

Mr. Raatz reported that he plans to discuss the MISO long-term power supply through the Request for Proposal process at the June Board meeting. Currently, we would like to buy some magnitude of capacity for two or three years, delaying the need for construction of an MISO asset.

23. Engineering & Construction Report, continued

A. Project Funding Chart

Senior Vice President-Engineering & Construction Matthew Greek reported that no Basin Electric contracts 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.

He noted that the LCS #4 and #5 units have still not been declared into commercial operation as we have not finalized all of our agreements with McKenzie. Meanwhile, we are accruing approximately $500,000 per month of interest during construction. If we continue without declaring units 4 and 5 into commercial operation for a few more months, we will approach the approved project budget of $107.9 million.

24. Transmission Report

Senior Vice President of Transmission Mike Risan reported that as of April 28, 2017, employees in the Transmission System Maintenance Division had worked 178 days without a DART incident. He presented a photograph of a dragline shovel preparing to move under the AVS-to-Broadland transmission line west of AVS.

A. Bowman Substation Land Purchase (Clarification)

Mr. Risan reported that the Bowman Substation is located on the Miles City-to-New Underwood 230-kV transmission line. Basin Electric owns much of the 230-kV bus, including the 230-kV breakers. Slope Electric Cooperative, Inc. (**Slope Electric**) purchased the Bowman Substation facilities that Upper Missouri Power Cooperative (**Upper Missouri**) owned. Board approval was granted in December of 2016 for Basin Electric to purchase the 230-kV bus that will be recovered in the SPP Tariff.

The clarification staff is requesting is that Basin Electric will be purchasing the 230-kV bus at the Bowman Substation, as well as the substation land and associated common facilities (fence, control building, etc.). The purchase amount remains at the already-approved estimated cost of $260,000 and no additional funds are being requested. He recommended approval of a new resolution clarifying this purchase.

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

R04.05-09-17 RESOLVED, that the CEO and General Manager, or his designee, be authorized to enter into a purchase agreement with Slope Electric Cooperative, Inc. for the Bowman Substation land, common facilities and 230-kV bus at an estimated cost of $260,000, subject to satisfactory negotiation of the final contract language.

B. Southwest Power Pool

Mr. Risan reported on the April 25 SPP quarterly board meeting and Basin Electric's request for reconsideration of the timing for the Roundup-to-Kummer Ridge 345-kV line due to reduced load growth forecasts in western North Dakota. SPP conducted a preliminary, expedited evaluation and agreed with our assessment. We anticipate the Notice to Construct will be withdrawn after their final review. At the same time that we notified SPP about the Roundup-to-Kummer Ridge line, we also brought to their attention two transformers in north central North Dakota that may not be required due to the revised lower load forecast.

He noted that Basin Electric built the first leg of the North Killdeer Loop believing that it was clearly needed and that it would be eligible for SPP cost sharing; however, due to the urgency of serving the load growth, construction of the line was started before we received SPP's authorization to construct the line.

With this other issue of not completing the second phase (Roundup-to-Kummer Ridge), we're in a situation where the first phase may not be considered eligible for cost sharing because it is now radial and technically not classified as transmission. Western and Missouri River Energy Systems are questioning this line and claiming it is not eligible for cost sharing based on this technicality.

The next step in the process is for the parties to elevate the matter to senior management for the next level of conversation. Tom Christensen has been the lead in this effort and will now offer Mr. Risan's name for Basin Electric and will recommend Bob Harris be nominated for Western. In our approach, we were trying to do the right thing to meet member load growth but got caught up in different processes as we transitioned into SPP. We went through the Mid-Continent Area Power Pool approval process and ultimately this line was to be a network facility which was needed after our integration into SPP, hence satisfying the "need by date" concept required for cost recovery. We think it's reasonable, but we've been asked these questions.

SPP approved the Southwest Minot-to-Ruthville 115-kV line. We expect the Notice to Construct to be issued in the names of both Central Power Electric Cooperative, Inc. (**Central Power**) and Basin Electric since both are SPP members. It is expected that Central Power will want to build that line since it owns the substations at both ends, the line is in their service territory and the voltage is more typical of their construction and maintenance capabilities.

Subsequent to the SPP board meeting, we received official notification that the Notice to Construct for the two transformers at Neset and Blaisdell Substations will be withdrawn due to the reduced load forecast. He noted this will have no impact to the transmission system. Should loads recover, new Notices to Construct could be reissued.

C. Mountain West Transmission Group

Mr. Risan presented a graphic of the footprints of MWTG and SPP, including the DC Ties. Negotiation topics include west-side AC and DC tie cost allocation, administrative and exit fees and the extent to which SPP could have different tariff provisions on the east and west.

SPP was criticized for not being as open and transparent as it could have been when the Integrated System joined SPP, so there is now a more defined process for new member integrations. The SPP stakeholder process has two representative stakeholder groups and all participants have signed nondisclosure agreements. About a month ago, MWTG authorized SPP to disclose to both groups some of the concepts MWTG will be requesting: west-only cost allocation, DC tie cost sharing, phased-in administration fee, exit fee, West Regional State Committee, Reliability Coordination strategy, Bylaws/Membership Agreement, open board voting, reservation of Transmission Owner Rights and Western Federal Service Exemption.

He then reviewed the SPP-MWTG negotiation timeline and noted that participants will try to pick up the pace in order to meet the July SPP board of directors meeting deadline. He noted that the Public Service Company of Colorado representatives have urged the parties to keep this deadline.

D. North American Electric Reliability Corporation

Mr. Risan reported that on the North American Electric Reliability Corporation (**NERC**) front, we continue work on our Midwest Reliability Organization self-certification and follow-up questions.

25. Human Resources Report

Senior Vice President of Human Resources Diane Paul reported that there were 48 retirements in 2016 and that as of May 4, 2017, 62 employees have provided notice that they will retire in 2017. She also noted that 592 employees (both Basin Electric and DGC) will be age 55-plus in 2017, so high retirement numbers will likely continue.

Ms. Paul reported that Basin Electric has 15 fewer employees and DGC has 27 fewer employees in May of 2017 compared to May of 2016.

Basin Electric was selected to receive a 2017 "Bismarck Mandan Top 10 Young Professionals Workplace" award from the Young Professionals Network. The selection criteria are based on innovation, inclusion and benefits.

A. Benefits Update

Manager of Benefits Plans Shawna Piatz reported that bids for Basin Electric's medical, pharmacy, dental and employee assistance programs have been received and are being evaluated.

B. NRECA Pension Plan Restatements

Ms. Piatz reported that the National Rural Electric Cooperative Association (**NRECA**) Pension Plan must be restated every five years to ensure that the plans remain compliant with regulations. The restated plans would be effective July 1, 2017. She presented the proposed resolution and recommended it be adopted.

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

R05.05-09-17 WHEREAS, Basin Electric Power Cooperative (the "Cooperative") is a participating employer in the Retirement Security Plan sponsored by the National Rural Electric Cooperative Association (the "Qualified Pension Plan");

WHEREAS, the Qualified Pension Plan must periodically be amended to comply with new or changed regulations, rulings, legislation and plan operations;

WHEREAS, the Cooperative desires to amend and restate the Qualified Pension Plan to clarify certain provisions of the

Qualified Pension Plan and make various amendments to the Qualified Pension Plan; and

THEREFORE, BE IT RESOLVED, that the Board of Directors of the Cooperative authorizes the July 1, 2017 amendment, restatement and continuance of the Qualified Pension Plan.

BE IT FURTHER RESOLVED, the proper officers of the Cooperative are hereby authorized and directed to take all action necessary to carry out the purposes of the foregoing resolutions including execution of the Adoption Agreements.

C. Safety Update

Director of Human Resources Lynn Beiswanger reviewed the Headquarters "Our Power, My Safety" focus card participation. The May 12 "People. Power. Purpose." presentation will be on Our Power, My Safety and the results of the recent safety perception survey.

D. Communications & Creative Services Update

Director of Communications & Creative Services Mary Miller presented some of the media created in-house for our members. The members' website was revamped through the merging of two former sites. She noted that membership needs are evolving. We are receiving more requests for digital pieces the members can share on websites and social media. Good feedback has been received from members on the low- and high-voltage retractables created for linemen appreciation day last month.

She presented two videos created in-house--one requested by Rushmore Electric Power Cooperative to increase awareness of demand management that was animated by Chelsey Ciavarella and the second a Touchstone Energy ad produced for Montana's electric cooperatives featuring Miss Montana.

Ms. Miller then recognized the 2017 annual report team: Andrea Blowers, editor; Nicole Perreault, designer; and Chelsy Ciavarella, photographer.

26. Government Relations Report

Vice President of Government Relations Dale Niezwaag reported on the NRECA Legislative Rally in Washington, DC where Basin Electric supported the Statewide groups and had side meetings on specific issues with members of the North Dakota Congressional delegation. The items discussed included advanced energy technology funding for the Allam Cycle and the Internal Revenue Code Section 45Q tax credit for Carbon Capture Utilization and Storage.

Discussion also included a waiver for use of the six Ghz bandwidth that was granted by the Federal Communications Commission (**FCC**) in the waning hours of the Obama administration to Higher Ground, a cell phone company trying to increase the power of cell phones so they can be used in more remote areas. This bandwidth is used by utilities (including Basin Electric, Tri-State, Minnkota Power Cooperative, Inc. (**Minnkota**) and Dairyland Power Cooperative) for microwave communications. NRECA has submitted a letter asking the FCC to rescind this waiver.

NRECA and Minnesota Rural Electric Association awarded the distinguished service award to Minnesota U.S. Representative Collin Peterson.

During the rally, Basin Electric staff met with EPA Administrator Scott Pruitt to weigh in on regional concerns related to the Clean Power Plan such as fixing the New Source Review regulations to allow efficiency improvements and being willing to explore ideas to give utilities certainty. Administrator Pruitt stated he wants to make decisions and rules based on data, not models. He asked Basin Electric and Minnkota to send a letter to President Trump expressing appreciation and support for the regulatory rollback.

Administrator Pruitt was invited to speak at Basin Electric's annual meeting.

President Trump's guidance orders require agencies to remove two rules for every new one; establish a regulatory budget which allows the President to set a fiscal cap on rules each year; require agencies to assess and consider both the benefits and costs of regulatory actions; and issue regulations only upon a reasoned determination that the benefits justify the costs. Basin Electric staff is reviewing EPA's proposals under the regulatory reform agenda.

Department of Energy Secretary Rick Perry has requested a study to assess whether federal policies have hurt the electric grid's reliability or supply of baseload power.

Mr. Niezwaag reported that the Federal Energy Regulatory Commission (**FERC**) has not had a quorum for several months and will soon be down to one commissioner. The President has nominated two people for the open FERC positions, one of whom is Neil Chatterjee, who was the energy staff person for senate majority leader Mitch McConnell. It was noted that Mr. Chatterjee is knowledgeable about cooperatives.

In 2009, Basin Electric helped the state of North Dakota draft laws and promulgate regulations for CO2 sequestration. The state of North Dakota then made a request to EPA to have primacy with respect to these regulations. This request has been sitting at EPA since 2013. Yesterday, North Dakota received a letter from Administrator Pruitt granting this request and authorizing the state to begin this process.

On May 4, staff participated in an NRECA fly-in to Chicago where G&Ts and the Statewide organizations discussed the Clean Power Plan. NRECA's main push is for EPA to come in with a new rule, but they want to keep it an "inside the fence" rule consistent with the provisions of the Clean Air Act which limit EPA to mandating modifications to power plants. It is the consensus of the staff that while this is a good approach from a legal standpoint, it may not be a strong long-term political strategy.

Mr. Niezwaag reported that the Wyoming and North Dakota legislatures had tried to adopt legislation requiring a mandatory baseload coal portfolio that required coal to constitute the primary generation source. This failed in North Dakota, but was turned into a proposed study of the effect the growth of wind generation has had on baseload coal generation.

A group of Wyoming commercial users went to the Wyoming legislative leadership and asked the legislature to study the electric rates charged in the state. Bill Stafford and Mike Easley will attend a legislative committee meeting which is scheduled for next week.

Legislative Representative Steve Tomac reported that he has resigned effective June 2 and expressed his appreciation for the opportunity to represent the Cooperative.

27. Financial Services Report, continued

Senior Vice President & Chief Financial Officer Steve Johnson distributed the Missouri Basin Power Project audit.

He reported that the Gross Domestic Product (**GDP**) for the first quarter of 2017 was anemic but was offset by the extremely strong payroll report. The second estimate for first quarter GDP will be issued on May 26. The markets are currently showing a 75 to 80 percent chance of the Federal Reserve tightening in June.

A. Review of 2017 Series A Bond Financing

Mr. Johnson reported that the $500 million 2017 Series A Bond Financing priced on April 19 at 99.635% with a 4.750 percent coupon for a 4.773 percent yield. The transaction closed on April 26, 2017 with 58 investors. Of these investors, 48 percent were asset managers, 48 percent were insurance companies, three percent were hedge funds and one percent was pension funds. He noted that Basin Electric achieved its goal of attracting a new investor base as this was largely a new pool of investors to the Basin Electric credit. However, many names of the insurance companies were carryovers that we'd seen in our private placement transactions.

He noted that the transaction went smoothly and he was generally very pleased with it. He noted that this was a Cooperative-wide effort.

B. Comments on Alan Spen's Presentation

Mr. Johnson commented on Alan Spen's remarks.

C. Accounting Report

Accounting Administrator Darla Kay Miller reported that the April 2017 Statement of Operations reflects a net deficit of ($5.3 million) compared to the budgeted net deficit of ($21.6 million) for a favorable variance of $16.3 million. The net margin last April was ($28.9 million).

Member sales were approximately $7.1 million lower than budget, including the March actualization of $0.1 million. April sales are estimated to be $7.2 million less than originally forecasted due to weather.

Surplus sales were approximately $1.5 million higher than budget, including the March actualization of $0.6 million. April sales are estimated to be $0.9 million more than originally forecasted. A positive volume and price variance of $0.4 million and $0.5 million are estimated, respectively.

Operations expense was $85.0 million compared to the budget of $96.1 million for a favorable variance of $11.1 million. Purchased power expenses were less than budget by $9.1 million. Fuel expenses were $1.3 million more than anticipated.

Maintenance expense was $16.7 million compared to the budget of $24.6 million for a $7.9 million favorable variance. This positive maintenance variance can primarily be related to the lower boiler maintenance at AVS and LRS which comprised $2.9 million and $2.7 million, respectively, of the positive variance. Year-to-date boiler expenses at LRS were $7.1 million less than anticipated.

Ms. Miller then reviewed year-to-date consolidated net income/loss and changes to the balance sheet and month-end cash. Long-term debt, net of current portion increased $486.6 million in April, primarily due to the issuance of 2017 Series A Bonds in the amount of $500 million.

Basin Electric's April equity-to-asset ratio was 18.4 percent compared to 19.8 percent in March. The April equity-to-capitalization ratio using the Moody's methodology (both without the consolidation entry for The Coteau Properties Company) was 21.5 percent compared to 23.1 percent in March. The April equity-to-capitalization ratio based on indenture requirements for patronage distribution was 21.6 percent compared to 23.8 percent in March.

28. Directors' Reports

Director Peltier reported Deb Erickson is running for a District #3 (Minnesota, North Dakota and South Dakota) board position at National Cooperative Services Corporation, an affiliate of National Rural Utilities Cooperative Finance Corporation, and has requested Basin Electric's support. Ms. Erickson is a member of Minnesota Valley Electric Cooperative in Jordan, Minnesota.

Director Gilbert reported that Scott Stecher, president of the Corn Belt board had sent a note of appreciation for the joint board meeting.

He reported that Midland Power Cooperative (**Midland**) will hold a ribbon-cutting ceremony for its Training Field on May 18. The training field features various distribution power line infrastructure equipment including underground lines, overhead lines, multiple meters, onsite generators and various other scenarios and has the capability of being energized for true-to-life work experiences. The training field will not only benefit Midland, but will also be available to others for education, training and/or testing purposes. The facility was made possible in collaboration from the Iowa Association of Electric Cooperative, and support from Rural Electric Supply Cooperative and various industry vendors.

29. Date and Time of Next Board Meeting

President Peltier noted that the next regularly scheduled meeting of the Board of Directors will begin on June 13, 2017 starting at approximately 1:00 p.m. CDT.

He reminded the directors that they would arrive in Bismarck for the strategic planning session at 6:30 p.m. on May 24, the session will begin at 8:00 a.m. on May 25 and finish by noon on May 26.

30. Executive Session

At 3:55 p.m., it was moved by Director Presser, seconded by Director Applegate and carried that the Board retire into executive session to discuss a potential purchase opportunity.

The Board arose from execute session at 4:37 p.m.

31. Adjournment

There being no further business to come before the Board, President Peltier adjourned the meeting at 4:38 p.m.

Gary C. Drost

Gary C. Drost
Secretary-Treasurer