Approved August 9, 2016

Basin Electric Power Cooperative
Bismarck, North Dakota

Minutes of the Regular Meeting of the Board of Directors
July 12-13, 2016

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The Regular Meeting of the Board of Directors of Basin Electric Power Cooperative (the **Cooperative** or **Basin Electric**) was held at the headquarters building, Bismarck, North Dakota, beginning on July 12, 2016 at 3:55 p.m. CDT.

1. Call to Order

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

2. Roll Call

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

Donald E. Applegate	Paul Baker
Leo Brekel	Gary C. Drost
Charles Gilbert	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, Tom Christensen, Tammy DeWitt, Matt Greek, Steve Johnson, Bryan Keller, Becky Kern, Gavin McCollam, Dave Raatz, Mike Risan, Ken Rutter, Susan Sorensen, Steve Tomac, Kevin Tschosik and Michelle Wiedrich.

Also present were Dakota Gasification Company (**DGC**) Vice President David J. Sauer, Upper Missouri Power Cooperative (**Upper Missouri**) directors Ray Clouse, Blaine Jorgenson, Dean McCabe, Jack Hamblin, Bill Retterath and Travis Thompson, Upper Missouri manager Claire Vigesaa and Upper Missouri staff members Della Pewonka, Stacey Brown and Jeremy Mahowald.

3. Approval of the Agenda

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

4. Approval of the Minutes

The minutes of the June 14-16, 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 Gilbert and carried that the minutes be approved as presented.

5. Upper Missouri General Manager's Report

Mr. Vigesaa thanked the Board for the invitation to meet with Basin Electric and he introduced the Upper Missouri directors present. He reported that Upper Missouri was organized in 1957 and is comprised of 11 cooperatives--six in Montana and five in North Dakota. Upper Missouri has only five staff members and so it relies on contractors for its chief financial officer position, engineering services and substation maintenance and testing.

Basin Electric supplies 96% and the Western Area Power Administration (**Western**) supplies 4% of Upper Missouri's power. A number of members have large Western allocations; however, Upper Missouri does not socialize the Western allocations. Upper Missouri's industrial loads include gas processing, oil wells, sugar beets, barley, malting barley, hunting, fishing, cattle, feedlots and one ethanol plant.

Upper Missouri has experienced unprecedented utility growth over the last few years. Last year's peak was 1,069 MW and it sold 7,116 GWh. Growth has slowed, but is now at 10.4% year over the year, which is still significant. Upper Missouri accounts for 30.8% of Basin Electric's sales. Not all of the Upper Missouri members are experiencing growth however.

Mr. Vigesaa reported that while the Bakken working rig count is down to 29, performance and technology have improved and there is a lot of gas collection, compression and processing being done so that continued growth is still expected. Homes and businesses are still being built, especially in the Watford City area.

Upper Missouri has made huge investments to serve its load, in particular, an $8 million 230/115/60-volt substation which doubled Upper Missouri's electric plant in one construction project.

The oil slowdown has resulted in huge impacts in the area; some reports claim that 20,000 people have left. He noted that roads, pipelines, water lines, gas collection lines and crude oil pipelines have been constructed and are in place. Housing has caught up and perhaps been overbuilt; however, there are still some people living in campers.

What remains is a more technical workforce, longer-term employment, better working conditions, better housing and less traffic congestion. He stated that Upper Missouri is prepared for the next growth spurt.

Mr. Vigesaa introduced Upper Missouri's chief operating officer, Jeremy Mahowald, who reported on Upper Missouri's current three main areas of concern: load monitoring, metering and North American Electric Reliability Corporation (**NERC**) compliance.

Mr. Vigesaa stressed that Upper Missouri understands the need for the recent rate increase and wants to keep Basin Electric strong, but that a generic commodity like electricity cannot be improved, so any time costs are added to a generic product, it is just an added cost. He stressed the importance of Basin Electric, Upper Missouri and the members increasing efficiencies and productivity and reducing costs so that we can remain competitive in the market.

He expressed his gratitude for Basin Electric's support with incremental generation and transmission development during the period of overwhelming growth and stressed that Upper Missouri is not overbuilt.

6. Basin Electric General Manager's Report

General Manager Sukut thanked Upper Missouri for taking the time to meet with the Basin Electric board. He then reviewed Basin Electric's load growth compared to the national average and total Basin Electric Williston Basin load growth. In 2000, Basin Electric's generation portfolio was made up of 85% coal generation; today that percentage is just 56.4%. We are going into a carbon-constrained world but Basin Electric plans to run its coal plants as long as possible because there is debt against them.

With reduced sales to the members, Phase III of the Pioneer Generation Station (**PGS**) and the Lonesome Creek Station (**LCS**) will be kept out of the rate base as long as possible, hopefully until January 1, 2017.

How did we get into this situation? Natural gas prices fell 22%, fertilizer prices fell 18% and the cost of crude oil decreased 40% resulting in a perfect storm of negative consequences. Austerity measures include a hiring freeze, cuts in contracted services, IS&T, travel and external training and delay of projects at the Great Plains Synfuels Plant (**Synfuels Plant**). The budgets were decreased between $85 million and $100 million. As of the end of May, the revised budget is $60 million lower.

Power sales decreased by 85 MW which contributed to the shortfall, so the 2017 forecast was reduced another 40-45 MW. Basin Electric has tried to show that it is running under budget but revenues were also under budget. In June 2016, the board approved a rate increase averaging 12% to be implemented at the beginning of August 2016.

In retrospect, Mr. Sukut reported that we didn't reduce enough in 2011. The board has challenged staff to continue the austerity measures and we are striving for process improvements. In addition, we are still working on freight rates, reducing the number of fleet vehicles and centralizing office supplies. Staff understands that this is hard for the members at the end of the line and how competitive the market is.

Mr. Sukut then reported on new members, retirements, the headquarters building addition, the Clean Power Plan (**CPP**) and the Horizons Committee.

7. Recess and Reconvention

At 4:48 p.m. President Peltier recessed the meeting until July 13, 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.

8. 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 Jamey Backus, Tracie Bettenhausen, Tom Christensen, Shawn Deisz, Tammy DeWitt, Mike Eggl, Elizabeth Erhardt, Pius Fischer, Matt Greek, John Jacobs, Steve Johnson, Amber Joyce, Kerry Kaseman, Bryan Keller, Becky Kern, Janet Kubisiak, Sharon Lipetzky, Gavin McCollam, Darla Miller, Deb Olafson , Diane Paul, Mike Paul, Curt Pearson, Dave Raatz, Josh Rossow, Dave Rudolph, Ken Rutter, Susan Sorensen, Myron Steckler, Steve Tomac, Kevin Tschosik, Amanda Wangler, Valerie Weigel and Michelle Wiedrich.

Also present were DGC Vice President David J. Sauer; Upper Missouri directors Ray Clouse, Michael Hoy, Blaine Jorgenson, Anthony Larson, Dean McCabe, Albert Paul, Bill Retterath, David Sigloh and Travis Thompson; Upper Missouri manager Claire Vigesaa; Upper Missouri staff members Jeremy Mahowald, Della Pewonka and Stacey Brown and KEM Electric Cooperative (**KEM**)/Mor-Gran-Sou Electric Cooperative (**Mor-Gran-Sou**)/ Roughrider Electric Cooperative (**Roughrider**) co-managers Chris Baumgartner and Don Franklund.

9. Executive Session

At 8:00 a.m., the board recessed into executive session to answer questions of the Upper Missouri Board. At 9:15 a.m., the board arose from executive session.

10. Western Fuels Update

General Manager Sukut reported that Western Fuels Association (**WFA**) CEO Meri Sandlin is settling in very well. She has cut costs at WFA by one to one and one-half cents per ton. The main issue is that Tri-State Generation & Transmission Association (**Tri-State**) and Basin Electric are carrying 60% of the load and each have coal for which they pay rail charges of 14 cents per ton but do not receive any rail service. Tri-State and Basin Electric are asking for relief from the other participants to get the cost structure back in line. He noted that WFA has 13 board members, of which Basin Electric and Tri-State account for six votes. Ms. Sandlin recently made a big sale out of the Dry Fork Mine that will lower the incremental cost of mining coal.

11. Office of General Counsel Report

Senior Vice President & General Counsel Mark D. Foss provided an update on the status of legal matters concerning the Cooperative, including the Laramie River Station (**LRS**) Best Available Retrofit Technology case and CPP litigation.

He reported that the three-judge panel of the Eighth Circuit Court of Appeals ruled in favor of the state of North Dakota/Basin Electric/Minnkota Power Cooperative, Inc. (**Minnkota**) in the lawsuit concerning the state of Minnesota's Next Generation Act on three different bases: the dormant Commerce Clause; the Federal Power Act; and the Clean Air Act. Minnesota Governor Dayton has stated that Minnesota will appeal to the full court.

A. Termination of Kit Carson Electric Cooperative Class C Membership

Mr. Foss reported that the Cooperative has been informed by Tri-State that Kit Carson Electric Cooperative (**Kit Carson**), a Class C member of Basin Electric, is no longer a member of Tri-State, a Class A member of the Cooperative. As Kit Carson is no longer a member of a cooperative holding a Class A membership in the Cooperative, Kit Carson is no longer eligible for Class C membership.

Section 6 of Article I of the Bylaws provides that the Board of Directors, by the affirmative vote of not less than two-thirds (2/3) of the members of the Board of

Directors, may expel a member which ceases to engage in the business which made it eligible for membership in the Cooperative.

Section 7 of Article I of the Bylaws provides that upon expulsion, the membership of an expelled member shall be cancelled and the Cooperative shall refund the original $100 Class C membership application fee within 60 days.

He recommended that the termination of Kit Carson's Class C membership be approved.

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

R01.07-12-16 RESOLVED, as Kit Carson Electric Cooperative (**Kit Carson**) is no longer a member of Class A member Tri-State Generation & Transmission Association, Inc. and thus no longer qualifies as a Class C member of the Cooperative, Kit Carson's Class C membership is hereby terminated and Kit Carson expelled from the Cooperative; and

BE IT FURTHER RESOLVED, that Kit Carson's membership fee be promptly refunded.

12. Transmission Report

A. Transmission Systems Maintenance Report

Vice President of Transmission System Maintenance (**TSM**) Bryan Keller reported that as of June 30, 2016, the TSM Division has worked 56 days without a Days Away, Restricted or Transferred (**DART**) incident. There were no personal injuries or vehicle incidents in the past month. TSM received some minor hail damage at Mandan TSM and wind damage at Beulah TSM during the month.

He reported on the July 1, 2016 transmission system outage on Western's Williston/Watford City 230 kV line due to a Phase C-to-ground line fault. Western's Williston 230 kV breaker 382 reclosed into the fault. Western's Williston East 230 kV bus protective relaying misoperated and de-energized the Williston East 230 kV bus and transformer KV1A. Protective relaying for the 13.8 kV bus of Judson 345/230/13.8 kV transformer KU6A operated for the external fault, de-energizing the transformer. McKenzie Electric Cooperative (**McKenzie**) personnel found a transformer mineral oil spill at the Timber Creek Tap. He presented photographs and discussed the Timber Creek Tap 230/115 kV Transformer KV23A.

B. Approval of Beulah TSM Shop Addition/Remodel

Mr. Keller reported that the original 2,100 square-foot Beulah TSM shop was built in 1984 and is very crowded. With the construction of the additional transmission in western North Dakota, a line crew will soon be needed in Beulah, adding to the congestion. The proposed 3,000 square foot addition to the existing shop will consist of supervisor offices, crew areas and lunch/conference/training rooms. The existing office/shop area, including the restrooms, will be remodeled. The existing steel siding will be replaced and an emergency generator and automatic transfer switch will be installed. He presented photographs and discussed the specific areas, diagrams of the addition and the costs for each portion of the addition/remodel, which totals $2,824,460. He recommended approval of the project.

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

<u>R02.07-12-16</u> RESOLVED, that the Beulah Transmission System Maintenance building addition and remodeling project as presented to this meeting is hereby approved at a not-to-exceed cost of $2,824,460; and

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

<u>Re-Evaluation of 115 kV Roundup-to-Kummer Ridge Transmission Line</u>. Manager of Transmission Rates Tom Christensen reported that Basin Electric requested that the Southwest Power Pool (**SPP**) re-evaluate the new Kummer Ridge-to-Roundup segment of transmission line because we believe 345 kV is needed and SPP approved the line at 115 kV. When reconsideration is requested, the issue goes through a committee process. SPP staff has recommended the 345 kV project, which was approved by the Transmission Working Group this week and will go before the Markets and Operations Policy Committee (**MOPC**) later today.

<u>Roundup-to-Kummer Ridge Corridor Complexities</u>. Director Presser reported that the Three Affiliated Tribes invited all oil producers to a July 6 meeting in Denver where they asked what they could do to get the oil industry back into the Tribal area. The resounding response was for the Tribe to grant rights-of-way on Tribal lands to McKenzie. While Mr. Presser hadn't yet heard whether that activity has begun, he recommended that the Right-of-Way staff be ready to complete Basin Electric's right-of-way at any moment.

Mr. Christensen reviewed the potential routes and U.S. Forest Service lands in the area. He reported that it was the belief of Transmission Services Director Matt Stoltz that we have one shot to get a transmission line through this area, so it needs to be a 345 kV line.

Mr. Christensen presented a map showing the AVS-to-Charlie Creek-to-Williston/Judson and over to Neset transmission line. Basin Electric has hard-wired approval for these segments and so will receive cost recovery for these segments. At issue is the North Killdeer Loop portion of line.

<u>MAPP 2015 Regional Plan</u>. Mr. Christensen reported that the Round up to Kummer Ridge-to-Patent Gate was included as part of the MAPP 2015 Regional Plan, so we think we can get cost recovery on this segment of the line.

<u>BEPC Settlement Update</u>. Mr. Christensen reported that Basin Electric's credit rating downgrade may put us in a better position going into a formal hearing. Our last offer was 9.5% Return-on-Equity with a 38% equity ratio and 1.90% depreciation rate. The counteroffer from Kansas/Missouri was an equity ratio of 37% and a depreciation rate of 1.95%. We are very interested in getting that locked in, so Basin Electric has tentatively agreed. There is one remaining intervenor, Missouri River Energy Services (**MRES**); however, we think we'll be able to get MRES to sign off.

<u>CTPTF Transmission Owner Selection Process Update</u>. Within SPP there is a process to have regional transmission projects competitively bid. SPP is re-evaluating this approach as a result of the Competitive Transmission Development Technical Conference held at the Federal Energy Regulatory Commission (**FERC**) several weeks ago.

Mountain West Transmission Group. Mr. Christensen reported that this group would be made up of utilities serving eastern Wyoming and Colorado: Public Service of Colorado, Tri-State, Western-Loveland, Western-Colorado River Storage Project, Colorado Springs Utilities and the Platte River Power Authority. A request for information was sent to four entities that could serve as administrator of a Mountain West regional transmission organization. Our initial thought is that we would prefer that the SPP administer the west-side transmission group. The next round of discussions has been scheduled for the last week in July. Reponses on the outstanding issues such as how the AC-DC-AC ties fit in and how to distribute point-to-point revenues are due July 15. The Brattle Group has been retained to conduct an economic study to determine the benefits of a west-side market. He noted that staff met with SPP on July 6 to discuss their thoughts on the treatment of the DC ties and governance issues.

NERC. Dave Rudolph, manager of transmission compliance, reported that the NERC Critical Infrastructure Project (**CIP**) standards went into effect on July 1, 2016. Eleven new or modified standards were implemented on July 1, containing 212 requirements. Staff had to develop 35 program documents to outline the activities. Basin Electric has no projects considered "high impact", but does have 13 "medium" Bulk Electric System cyber systems, as well as "low impact" facilities.

He reviewed the Operations & Planning Standards which are the traditional generation and transmission activities. Eight standards became effective in July. The next area, cyber and physical security of our assets, has been a very long, big effort. He thanked all who worked on the CIP team.

The other major item is developing a program that reduces risks to all facilities/entities. We have to know all of the facilities the cooperatives (Basin Electric and its members) own and then create a facility matrix so that compliance responsibilities for each of those facilities can be assigned. Staff is currently working on a facility agreement that requires that each cooperative has an obligation to maintain a current database.

13. Operations Report

Senior Vice President of Operations John Jacobs reported that there were no medical treatments and no 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 June generation for the owned and operated Basin Electric fleet came in at 2,136,002 MW compared to the budget of 2,190,522 MW, which is 2.4% under budget for the month. Generation for 2016 year-to-date is 5.8% below budget.

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

Unit	Availability	Running Plant Capacity Factor(net)	Unit Rating	Comments
AVS #1	99.78%	95.9%	450 MW	CP1 Charlie loss of power.
AVS #2	33%	85.3%	450 MW	Scheduled outage to place balance shot on turbine. Forced outage for fault

				relay opened yard breaker. Forced outage for generator exciter ground fault.
DFS	99%	101%	386 MW	Forced outage when B boiler feed pump tripped due to low flow.
LRS #1	92%	73.02%	570 MW	Scheduled outage to replace bonnet gasket on steam valve S12-1.
LRS #2	83%	78.02%	570 MW	Schedule outages to correct screen pluggage and remove fine screens.
LRS #3	99%	81.09%	570 MW	Forced outage for boiler furnace pressure problem and forced outage when operator shut down wrong piece of equipment.
LOS #1	100%	92.32%	221 MW	
LOS #2	83%	84.96%	448 MW	Scheduled outage for deslagging and SNCR tie-ins.

Integrated Test Center. Mr. Jacobs reported that we are still hashing out a few items with the state of Wyoming regarding insurance and terms and then he plans to bring the Integrated Test Center (**ITC**) host agreement to the board for approval in August. A committee was formed to review the technologies that will be utilized at the ITC. The first meeting is a conference call scheduled for tomorrow during which we will determine the process of vetting of technologies that will be tested at facility. That meeting will be followed-up by an in-person meeting of the Technical Review Committee either at Tri-State or at DFS. To date, there have been more than 200 applications to test at the ITC, including large players from all over the world. The real issue will be to weed out who is real and who isn't. Mr. Jacobs reported that now that the guillotine has been installed, there are 19 contractors that have prequalified to do the work; 15 of those 19 were invited to the site to review the scope of the work and do a walk-down. Of those 15, 13 actually visited the site. Bids are due July 29.

A. Distributed Generation Update

Distributed Generation Manager Kevin Tschosik reported natural gas prices for the distributed generating facilities (Groton Generating Station (**Groton**), Culbertson Combustion Turbine (**CT**), Wyoming Distributed Generation (**WDG**), Spirit Mound Station (**SMS**), Deer Creek Station (**DCS**), PGS and LCS) increased slightly during the month. June generation at the distributed generation facilities was as follows:

Unit	Monthly Availability	Monthly Generation	Unit Rating	Comments
Culbertson CT	92.67%	13,989 MW	100 MW	One outage. Big storm knocked Western line

				off so down for 20 hours.
Groton #1	87.09%	4,159 MW	100 MW	For generation. Had spring outage. Completed engine inspections.
Groton #2	82.13%	12,001 MW	100 MW	For generation. Had spring outage. Completed engine inspections.
SMS #1	0%	0 MW	60 MW	Did not run
SMS #2	0%	0 MW	60 MW	.did not run
DCS	93.42%	82,033 MW	300 MW	Also ran for load demand. Photos of HRSG enclosure.
PGS #1	33.77%	12,836 MW	45 MW	
PGS #2	33.92%	9,464 MW	45 MW	
PGS #3	34.27%	8,235 MW	45 MW	Charging motor failed on generator circuit breaker and took couple days to get one.
LCS #1	94.57%	17,314 MW	45 MW	Also provides regulation.
LCS #2	94.93%	18,498 MW	45 MW	Provides regulation.
LCS #3	90.8%	17,105 MW	45 MW	Provides regulation.

During June, PGS #1 ran 3335.73 hours in synchronous condensing mode and LCS for zero hours. The WDG had 21 west-side spinning reserve events for the month.

PrairieWinds ND (PWND). Annual maintenance is 43% complete. He presented photographs and reported that wind speeds up to 78 mph blew the nacelle from the Nordex south tower ("Wally") south of Minot. He noted should a gearbox fail on either of these Nordex towers, he doubted it would be economical to repair due to the age of the technology.

PrairieWinds SD (PWSD). Annual maintenance is 100% complete. Staff is working on weed issues.

The east-side peak occurred on June 19, 2016 at hour ending 1900 hours. At that time, wind generation was as follows:

Wind Project	Load Factor during the Peak	Capacity Factor		Project Total
		Month	YTD	
Baldwin	94 MW	46%	44%	99 MW
Campbell County	92 MW	51%	51%	88 MW
Day County	73 MW	53%	50%	99 MW
Edgeley	25 MW	31%	32%	40 MW
Highmore	19 MW	40%	40%	40 MW
Iowa Wind	23 MW	31%	42%	45.1 MW
Other Projects (Chamberlain & Pipestone)	0 MW	43%	53%	3.4 MW
PWND	113 MW	41%	43%	123 MW
PWSD	59 MW	43%	46%	162 MW
Wilton	90 MW	43%	41%	99 MW
Total Monthly Wind Generation	588 MW	43%		800 MW maximum
Average Capacity Factor		43%	44%	

B. <u>LOS Plant Update</u>

LOS Plant Manager Jamey Backus reported that the LOS employees reached a milestone of three million hours (October 24, 2006 through April 28, 2016) without a DART incident. It has now been 3,054,913 hours since the last DART case. He met with the boiler attendant team, a fairly new group of employees, regarding safety. He then presented photographs and discussed safety improvements at the plant, including the installation of a guardrail around the scrubber equipment, fixing undercutting on the banks of the Missouri River and installation of a handrail on top of the magnesium sulfide tank.

Year-to-date, LOS has produced 93.5% of its budgeted generation, with Unit #1 at 107.1% of budget and Unit #2 at 87.8% of budget.

LOS Unit #2 had an outage June 14-16 to deslag the boiler, tie-in power to the selective non-catalytic reduction (**SNCR**), install 28 SNCR nozzles into the boiler and repair three tube leaks. There was an outage July 5-7 to replace a blown forced-draft fan discharge expansion joint and repair a small tube leak.

Mr. Backus then presented photographs and diagrams and reported that staff is working to finalize design and engineering of the bottom-ash system. A change in the coal combustion residual (**CCR**) rule from the Environmental Protection Agency

(EPA) has altered the completion schedule. The contract is being issued to United Conveyor for equipment and services to ensure delivery by July of 2017.

The current coal inventory contains 615,251 tons of lignite and 92,280 tons of Powder River Basin coal.

C. LOS Coal Pond Expansion and Ditch Diversion

Mr. Backus reported that in April of 2015, EPA issued the CCR rule and in September 2015 issued the Effluent Limitation Guidelines rule. At that time, a decision was made to close the LOS ash pond and install a closed-loop ash-dewatering system. The ash pond was also used for coal gallery drains, V-slot sumps and coal-pond discharge.

The current coal pond is too small to handle these flows. Pond expansion and a new ditch will allow for proper settling time and diversion to meet North Dakota's discharge requirement.

He presented a photograph of the current pond which is 60 feet by 180 feet and a diagram of the expanded pond which will be 80 feet by 500 feet. A pond liner will be installed to prepare the station for future regulation. He recommended that Capital Project Request (CPR) #150225 for the coal pond expansion be opened at an estimated cost of $3,934,632.

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

R03.07-12-16 RESOLVED, that Capital Project Request #150225 for the LOS Coal Pond Expansion at a cost not to exceed $3,934,632 is hereby approved; and

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

14. Commodity Risk Management Report

Manager of Commodity Risk Kerry Kaseman reported that the average natural gas hedged price for 2016 is $2.50/dekatherm (dkt), increasing each year to $3.22/dkt for 2021. He reported on the current hedge position for natural gas in storage.

He reviewed the Ventura Forward Curve which, as of July 1, 2016, starts at $3.06/dkt for 2016, climbs to $3.18/dkt for 2017 and falls to $3.07/dkt for 2020.

There were no settled financial hedges for natural gas in June. He reviewed the Mark-to-Market (MTM) gain of $232,000 for natural gas.

He reviewed the current hedge position for west surplus sales, which reflected a 2016 average on-peak hedge price of $24.94/MW and off-peak hedge price of $17.14/MW. The current hedge position for east purchase power was $22.94/MW on peak and $22.25/MW off peak. He reviewed the Palo Verde On-Peak Forward Curve which, as of July 1, 2016, started at $32.47/MW for 2016, drops to $31.04 for 2017 and ended at $32.92/MW for 2020. He reported that June settled financial hedges for 40 MW of power resulted in a gain of $36,300. He reviewed the MTM Power loss of $373,000, which does not include the negative $17.2 million MTM on a long-term physical contract.

He reviewed the current hedge position for diesel, which reflected a 2016 average hedged price of $2.17 per gallon for 2016, $2.44 per gallon for 2017 and $2.56 per gallon for 2018 and showed little change month to month. He reviewed the Energy Information Agency's on-highway diesel price projections which, as of July 1, 2016, started at $2.48 per gallon increasing to $2.68 per gallon for November 2018. The June settled financial hedges for diesel resulted in a gain of $11,400 on a 77,000-gallon diesel hedge. As of June 30, 2016, the diesel MTM was a gain of approximately $411,000. The aggregate settlement for all commodities for the month was $47,700 and ($244,355) year-to-date, which did not include the MTM gain/loss on premiums and ineffective hedges. He then reviewed the $269,000 million gain on MTM for all commodity hedges, liquidity position and credit exposure by Moody's credit ratings.

Mr. Kaseman reported that the Cargill contract sets an exposure limit of $7 million. That exposure currently stands at $17 million which has resulted in posting a $10.2 million cash collateral with Cargill.

15. Recess and Reconvention

At 11:50 a.m. President Peltier recessed the meeting until 12:45 p.m., at which time the meeting reconvened with President Peltier continuing to preside and Secretary Gary C. Drost continuing to keep the minutes.

16. Roll Call

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

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

Said persons being all of the Directors of the Cooperative. Also present were Chief Executive Officer & General Manager Paul M. Sukut, Assistant Secretary Mark D. Foss and Basin Electric staff members Lynn Beiswanger, Tracie Bettenhausen, Don Boehm, Andy Buntrock, Tom Christensen, Tammy DeWitt, Ken Dolan, Mike Eggl, Elizabeth Erhardt, Pius Fischer, John Frank, Matt Greek, John Jacobs, Steve Johnson, Amber Joyce, Kerry Kaseman, Becky Kern, Janet Kubisiak, Sharon Lipetzky, Jim Lund, Jay Lundstrom, Tracy McBride, Sally Meier, Dale Niezwaag, Deb Olafson, Diane Paul, Curt Pearson, Dave Raatz, Ken Rutter, Susan Sorensen, Myron Steckler, Steve Tomac, Chris Vizenour, Amanda Wangler, Valerie Weigel and Michelle Wiedrich.

Also present were DGC Vice President David J. Sauer; Upper Missouri director Anthony Larson; and Upper Missouri manager Claire Vigesaa.

17. Marketing & Asset Management Report

Manager of Marketing & Financial Analytics Valerie Weigel reported on the North Hub, Minnesota Hub and Palo Verde forward pricing, noting that above normal temperatures coupled with reduced fuel switching because of higher priced gas lead to a mixed outlook for the July fuel burn. June averaged 31.7 bcf/day which is about six percent higher than last year. The increase, in part, has been due to gas being used for more baseload generation due to the coal plant retirements that have occurred since 2015, as well as economically motivated fuel switching. The balance of Palo Verde and Minnesota Hub prices remain tight while SPP prices remain under both.

West-side resources were online throughout the month with only a few small derates or outages. Volumetrically, Basin Electric sold an average of 160 MW in the on-peak hours in the day-ahead market and 25 MW in the off-peak hours. This includes sales in the west and sales into SPP across the ties. Palo Verde saw higher day-ahead prices in June than in past months.

Volumetrically, Basin Electric sold an average of 75 MW in the on-peak hours in the day-ahead market and 35 MW in the off-peak hours. This includes sales in the west and sales into SPP across the ties.

Even though we saw higher locational marginal prices (**LMPs**) in June, Basin Electric was a net buyer for the month. AVS #2 and LOS #1 and #2 were on outage at various points throughout the month. As primarily a net buyer in SPP in June, Basin Electric's purchased power price was greater than anticipated in the last half of the month. Even though there are days when we are net buyers, there can be hours during that day when we are selling into the market.

DCS was started nearly every day in June and had very high LMPs and so captured a margin over fuel and variable operations and maintenance of $11.92 per MWh.

In June, the Fort Thompson-to-Grand Island 345 kV line outage heavily impacted congestion coverage for the month. DCS, Neal #4, Crosswinds and Spirit Mound LMPs experienced high positive congestion, while Crow Lake experienced negative congestion. We anticipate this outage again in August as this was publically posted on the OASIS.

Senior Energy Marketing Analyst Amber Joyce reported that the market benefits of load management can be broken down into energy, transmission and capacity. We are looking into a load management program triggered by market pricing rather than load levels. We would like to look to capture energy revenue opportunities during high-market conditions, shift energy costs from high LMP hours to low LMP hours and capture the cost spreads between the day-ahead and real-time markets.

She reported that staff continues to reach out to all members interested in load management. Member participation is voluntary. Average controllable loads are 85 MW in the winter and 120 MW in the summer. East River Electric Power Cooperative (**East River**) has gone through five tests and Northwest Iowa Power Cooperative (**NIPCO**) has gone through two. We have found a lot of synergies from working with more than one member at a time. We have reached out to Central Power Electric Cooperative, Rushmore Electric Power Cooperative, Corn Belt Power Cooperative as well as Upper Missouri.

The high-level day-ahead process is to review forecasted LMPs with the members, work with the members to determine load management, update the demand bids and, at 4:00 p.m. after the commitment is made, review the day-ahead cleared prices.

The high-level real-time process is more of a matter of monitoring the markets and communicating with the members. The process is for Basin Electric to work with member throughout the day to determine control and restoration; the member providing validation of control; at the end of month, determine if the member controlled for its own demand or if controlled for economic dispatch during the time of the peak and, if so, share in revenue based on sharing mechanism.

There would be no impact to member rates or to special rates if a member decided to remove some loads from electric heat rate or interruptible rate to participate in program.

Between now and August, staff will work through validation, implement with East River and continue testing with other members. During the fall, Marketing will work with IS&T and members to automate load management, communicate to Class A members and test with other members. By the winter of 2016/2017, we would like to implement program for whole membership.

Members would still be responsible to manage their peak because we bill for the month based on actual metered load demand at the time of the peak.

Director Pearson reported that he heard no complaints about water heaters during the test.

Ms. Weigel noted that the average prices of the natural gas hedge plan are within the targets.

18. Cooperative Planning Report

A. Nemadji Trio Energy Center

Vice President--Cooperative Planning Dave Raatz reported that he had anticipated execution of the definitive agreements in August which would commit all parties to the project and that the agreements would be effective September 1, 2016. Since the June board meeting, Minnesota Power (**MN Power**) has requested we delay execution of those agreements until December 20 due to their recent discussions with the Minnesota Public Utilities Commission (**MN PUC**). As a result of those discussions, MN Power is issuing a request for proposal and will be comparing the Nemadji Trio Energy Center (**NTEC**) partnership project with other market opportunities including renewables and demand side management. Mr. Raatz reported that the one economics show that natural gas is a competitively priced resource. The MN PUC has asked MN Power staff to do additional analysis looking at wind and other types of power purchases and maybe demand side management alternatives compared to a natural gas combined-cycle resource.

While MN Power probably won't complete the process by December 20, 2016, it will have a better understanding following their analysis of the request for proposal submittals. In discussions with MN Power, they also mentioned the uncertainty of the load growth of the iron ore processing and copper, nickel and big smelter loads.

In a call last week, Dairyland Power Cooperative (**Dairyland**) and Basin Electric expressed concern regarding the delay and asked that MN Power make a commitment to the project by December 20, 2016. On an interim basis, MN Power has agreed to continue to develop the NTEC and to pay expenses for the next couple months, approximately $500,000 to $600,000. If the project proceeds, that amount will be divided among the project participants. If the project does not proceed, Basin Electric and Dairyland will not have to pay those costs. The parties discussed how to manage the load risk should MN Power seek potential off-takers and/or if the iron range load doesn't develop. MN Power may seek five to 15-year power sale agreements with other entities to sell a portion of this resource. MN Power asked if Basin Electric or Dairyland could purchase additional amounts of generation in the long-term. MN Power said it is not interested in an asset-type sale, but it is willing to discuss other options.

While Basin Electric is particularly interested in operating the plant itself, Mr. Raatz noted that the agreements do give MN Power the right to unload part of its ownership and continue to be the operator unless there is cause to remove it as operator. MN

Power is not yet ready to give up ownership and operation. MN Power agreed that the decision makers are still only MN Power, Dairyland and Basin Electric.

Mr. Raatz reported that Basin Electric's risk is having no project unless and until MN Power commits to this project and that it would take approximately five - six years to develop an alternative. When asked if MN Power would give site control to Basin Electric, MN Power said no. The December 20, 2016 date is important because milestone payments, transmission payments and the costs of environmental permitting are due in early January of 2017. Both Dairyland and Basin Electric have objected to making these payments unless the project agreements are signed.

The NTEC commercial operation date to be at the end of 2022. Basin Electric's engineering group has indicated there is still time to move forward with a different project if necessary if the NTEC project agreements are not executed in December.

Mr. Raatz stated it was staff's belief that we should continue with the project and proposal as offered; however, extension of the document execution timeline requires unanimous agreement of all three parties. As a result, if the project agreements are not executed by December 20, 2016, Dairyland and Basin Electric will need to seriously evaluate other resource alternatives.

A conference call of the NTEC project participants has been scheduled for July 19 and a steering committee meeting for August 16.

MN Power stated that it is still committed to the project and that this is just an unanticipated wrinkle in process with the partnership. Mr. Sukut reported that Dairyland and Basin Electric requested a conference call among the three CEOs.

B. <u>New Montana Cooperatives</u>

Mr. Raatz reported that Fergus Electric Cooperative (**Fergus**), Mid-Yellowstone Electric Cooperative (**Mid-Yellowstone**) and Tongue River Electric Cooperative (**Tongue River**) have asked if their power supply contracts could begin January 1, 2017 rather than October 1, 2017. As was discussed with the board last month, such action will require Basin Electric board approval in August or September of 2016 because certain representations must be made to Western and Northwestern Energy. This proposal will be discussed further during a meeting scheduled during the July 20 Managers Advisory Committee (**MAC**).

Mr. Raatz reviewed the three options that will have been submitted to the new members and will request a response on July 20. In addition, Mr. Raatz reported that Powder River Energy Corporation (**PRECorp**) is considering forming a G&T (Class A) classification which could start up once power deliveries under these new power supply agreement begin.

C. <u>Potential Minnkota Membership</u>

Mr. Raatz reported that work continues on the term sheet regarding Minnkota's possible membership in Basin Electric. The timeline is unchanged but the economics have not yet been re-run. Basin Electric's financial forecast is a key input into this re-evaluation. If Basin Electric maintains its rate increase, we would have to see where the economics come out and we will need to re-evaluate the CPP risks. Staff will continue to work on this over the next few months. Mr. Sukut noted that one of the hurdles is load management operations and reimbursement. The associated rate impact within Minnkota.

D. PURPA Assignment

Mr. Raatz reported that the Public Utility Regulatory Policies Act (**PURPA**) will be a topic of discussion at the MAC next week. In March of 2016, the Basin Electric board adopted a resolution that allows Basin Electric to accept its members' PURPA obligation on projects of 150 kW or more. Staff has been working on the assignment process. On June 30, Basin Electric sent a memorandum to its members reviewing the draft petition and implementation plan and requested a certified board resolution from each Class A and C member. If the members want to move their PURPA obligation to Basin Electric a public notice will need to be placed in local newspapers, after which a filing will be made with FERC.

Mr. Raatz noted that PURPA is not new; it was enacted in 1978 and Basin Electric has had a PURPA rate since that time and FERC has recently issued a new ruling on PURPA.

What was unique about the June 18, 2016 FERC ruling is that it states that the G&T is not entitled to recover its stranded investment from the member purchasing from the qualifying facility and thus the balance of the members of a cooperative must subsidize the member cooperative contracting with the qualifying facility. Under the new PURPA interpretation, in theory, a member could buy power from a qualify facility and displace Basin Electric's power supply.

Staff is discussing this situation with the Legal Department and with outside counsel Schiff Hardin. Requests for rehearing are due no later than July 15. Tri-State will request a rehearing and would appreciate Basin Electric's support. Associated Electric Cooperation expressed interest in partnering with Basin Electric on a request for rehearing. As a result, Schiff Hardin is preparing the draft for Basin Electric and Associated to file in support of Tri-State's request for rehearing.

Mr. Foss noted that Basin Electric will file for reconsideration of this FERC decision, after which FERC can either reconsider or uphold the existing decision. If it upholds its existing decision, Tri-State and Basin Electric could file an appeal with the DC Circuit Court of Appeals.

E. Rate Competitiveness

Mr. Raatz identified areas where Basin Electric has large amounts of load at potential risk to consumer self-generation alternatives. He noted it was interesting to think about some of the processes or discussions with members in the recent past. Most recently, we lost two member municipal loads, the city of Auburn (0.4 MW) and the city of Pocahontas (3 MW), which signed with the lowest market bid alternative. Competition is very tight due to low market conditions.

Mr. Raatz reported on a discussion regarding the power supply to East River's 20 MW Southern Minnesota Beet Sugar Cooperative load. They have made a decision to convert their coal boiler heat source to natural gas due to all of the CO_2 issues and the political bias against coal and they are now evaluating their alternatives for self-generation. When asked, Basin Electric had to state that its bid was the best it could do. The beet sugar cooperative's executive team will make a final decision in a couple months.

It will ultimately come down to what is the return on the capital investment? What is the availability of the capital? How do they stand the risk of natural gas prices? After the discussion with sugar beet staff, there were more discussions with East River asking what Basin Electric can do when the members and consumers have the idea that electric power will soon be 10 cents. If we had a forecast that showed constant rates into future, it would be something the membership could potentially use to forestall this 10-cent power perception and would give distribution cooperatives ammunition.

Upper Missouri asked what happens with the gas processing plants in their area? At $3 gas with an 80% load factor, self-generation costs approximately $70/MWh. It would be an advantage to the membership if we had a forecast showing stable rates going forward.

F. Member Load Forecast

Director of Utility Planning Becky Kern noted that last month Dave Raatz had discussed member load levels and that the 2016 forecast wasn't performing as expected.

She reviewed the total member summer peak demand and the Basin Electric summer load forecast under the actual, 2016 update and 2015 recovery cases for the years 2000 through 2034.

She reported that staff has begun conducting quarterly forecasts in a new, top-down format (Class A versus Class C), with broad economic and demographic drivers such as state Gross Domestic Products, population and using regional weather sites to model energy and demand for Class A member load.

Putting all of this updated information together for the balance of 2017, she is seeing an average reduction for the balance of 2017 of 125 MW whereas last month we discussed an average 86 MW reduction for Aug through Dec 2016.

Ms. Kern recommended authorization to adopt a new Member Load Forecast (July 2016 Load Forecast) for inclusion in Basin Electric's 2017-2026 Financial Forecast and to be used for future Power Supply Analysis.

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

R04.07-12-16 RESOLVED, that the Board of Directors hereby adopts the new Member Load Forecast (July 2016 Load Forecast) for inclusion in Basin Electric's 2017-2026 Financial Forecast and to be used for future Power Supply Analysis.

G. Wind Update

Antelope Hills. Ms. Kern reported on discussions with SunEdison regarding the termination of the project due to the failure to begin construction and the project not being in service by the contract date June 30, 2016 COD, the $5 million of liquidated damages, as well as Basin Electric's collection of the $5 million under the letter of credit.

Wind Update. Ms. Kern reported on the ongoing discussions with entities in the SPP footprint that were shortlisted. We have asked for delays in the commercial operation dates going to 2019 or 2020, repricing and extension of the term to 25 years or 30 years. In order for a commitment to be made in October 2016, the contracts would be negotiated and developed by September of 2016. She compared the size, cost, term, interconnections, developer and commercial operation dates of various North and South Dakota wind projects, as well as SPP wind shortlisted prices, whole picture economics and the 2023 wind project profit impact of Basin Electric being the off-taker of individual wind projects.

Ms. Kern then reviewed the power supply planning timeline, noting that long-term power supply decisions would be made in the August to November 2016 timeframe.

Contract negotiation will begin soon. We will request for either equipment guarantees or production guarantees. Staff has tried to balance the amount of wind power and natural gas power in our portfolio; however, by the end of 2016, the generation capacity portfolio will contain more wind power than natural gas due to a number of different wind projects coming online by the end of 2016.

19. Engineering & Construction Report

A. Project Funding Chart

Engineering Services Director Gavin McCollam reported that four Basin Electric contracts totaling $23.6 million would be presented for approval this month. He presented the listing of all current major projects along with the approved budget amount, total dollars committed and completion dates.

B. 345 kV Projects Update

Project Manager Amanda Wangler reported there was one recordable incident at the Patent Gate-to-Kummer Ridge transmission line project. As a result, some safety and awareness procedures in the field were changed. Staff is beginning nesting bird surveys and continuing cultural studies as needed. The Roundup, Patent Gate and Kummer Ridge Substations and the Patent Gate-to-Kummer Ridge line projects have been delayed due to late delivery of the power transformer and heavy rains. The Roundup high side was energized during the month. Work on Phase 3 of the AVS Switchyard and Phase 2 of the Charlie Creek Substation began June 15 and is projected to be completed by the end of 2016. The Judson-to-Neset line segment is scheduled for energization on October 31, 2017.

C. Award of Tande Substation Electrical Construction Contract

Ms. Wangler reported that the Tande Substation electrical contractor will be responsible for construction of the substation including all foundations, equipment installation, bus work and wiring, as well as the 345/230 kV greenfield substation to tie the Judson Substation to the Neset Substation. Work will begin in August and be complete in October of 2017. Forecasted contingency use on the North Killdeer Loop (NKL) changed this month and includes the Patent Gate-to-Kummer Ridge segment, all three substations and the line from Roundup-to-Kummer Ridge that has not yet been approved by SPP. She reviewed the lump-sum contract bids and recommended that the contract be awarded to the low bidder, Highmark Contractors, LLC, for $4,665,490. The project budget is $6.1 million.

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

R05.07-12-16 RESOLVED, that the electrical contractor contract for the Tande Substation be awarded to Highmark Contractors, LLC in an amount not to exceed $4.7 million; and

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

Ms. Wangler then reviewed the AVS-to-Neset project costs and the North Killdeer Loop project costs.

D. Award of LRS SCR Fall 2016 General Work Contract

Senior Project Manager Jim Lund reported that the scope of this contract includes selective catalytic reduction (**SCR**) column foundation installation, demolition of the auxiliary boiler, mechanical work and electrical work including the required conduit relocation. He presented a schematic of the SCR foundations which will require a five-week outage starting September 17 to work in the fan room. Seven prequalified bidders and bids were received in May followed by four rounds of clarifications. The budget for this contract is $4.64 million. He reviewed the bid summary and recommended that the contract be awarded to the low bidder, CCC Group, Inc., which also meets the Cooperative's technical and safety requirements.

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

R06.07-12-16 RESOLVED, that the LRS SCR Fall 2016 General Work contract be awarded to CCC Group, Inc. in the amount of $4.4 million; and

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

E. Approval of LRS Unit #3 Circulating Water Pumphouse Electrical Upgrade Budget Increase

Electrical Engineer Trenton Schwahn reported that this project is needed because the electrical equipment at the cooling towers for each unit is obsolete and requires replacement to insure safe, reliable and maintainable operations. The project scope is to replace all of the existing motor control centers, 480-volt switchgear, transformers, cable and wiring devices associated with the cooling towers. The board approved this $20.4 million project in March of 2014.

Work was completed at LRS Unit #1 during the 2015 outage, at LRS Unit #2 during the 2016 outage and is scheduled for Unit #3 during the 2017 outage. He presented photographs of the work done in Units #1 and #2 and noted that the electrical building construction costs were higher than expected.

As previously approved by the board, the cost of this project was $20.4 million; costs to date total $15.1 million; total committed to date is $15.2 million; the requested budget amendment is $3.5 million and the proposed new project budget is $23.9 million.

Unit #1 cooling tower maintenance has resulted in an approximate savings of $200,000 per year per unit and the reduced power consumption has resulted in an energy savings of approximately 5,000 MWh hours per year resulting in a revenue increase of $115,000 per year per unit.

The project justification was (and is) to replace obsolete equipment and to meet reliability and safety issues. Mr. Schwahn recommended the budget increase be approved.

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

R07.07-12-16 RESOLVED, that the budget for the LRS Circulating Water Pumphouse Electrical Upgrade project be increased $3.5 million ($1,479,450 Basin Electric cost) to a new total of $23.9 million, subject to the approval of the MBPP Management Committee; and

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

F. Award of LRS Circulating Water Pumphouse Electrical Upgrade Contract

Mr. Schwahn reported that the scope of this contract is to demolish the old equipment and install new 6,900-volt cables between the circulating water pumphouse transformers, circulating water pumps and the Unit #2 6,900-volt switchgear; refurnish the existing electrical systems in the cooling towers such as lighting, receptacles and junction boxes; and install new heat trace and associated control panels in the existing cooling towers.

Berwick Electric Company (**Berwick**) was the competitive low bidder on Unit #1 at $3.4 million. Berwick has offered to complete the Unit #3 work for the same price as in Units #1 and #2. Mr. Schwahn noted that Berwick performed at a high level on the Unit #1 and #2 projects and has a strong safety record. Berwick's high degree of familiarity with the work required to complete the cooling tower electrical installation will allow for completion of this project within the compressed Unit #3 outage schedule. He recommended the contract be awarded to Berwick.

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

R08.07-12-16 RESOLVED, that the construction contract for the LRS Unit #3 Circulating Water Pumphouse Electrical Upgrade be awarded to Berwick Electric Company in an amount not to exceed $3.4 million ($1,737,180 Basin Electric cost); and

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

20. Communications & Administration Report

Senior Vice President--Communications & Administration Mike Eggl distributed Basin Electric's Policy on Guiding Principles, Protocols and Practices. He asked for director comments/revisions and noted that action would be requested in August. It was noted that the Bylaws call for board meetings to be conducted according to Robert's Rules of Order except as otherwise agreed to by the board. Mr. Foss noted that, to the extent that we diverge from Robert's Rules of Order, it's a good idea to maintain a written policy of the deviations and this policy sets forth those exceptions.

Senior Legislative Representative Dale Niezwaag reported that the Brady II wind farm was approved by the North Dakota Public Service Commission (**NDPSC**). Many landowners had objections to turbine placement and/or objections concerning eagle habitat. The ND PSC increased setbacks so no turbine will be within 2,000 feet of the residence of a participating landowner and not within 2,600 feet of a non-participating landowner. Blinking lights were also a problem. As a result, the Brady II wind towers will have automatic aircraft warning lights.

In addition, NextEra implemented three types of payments for wind farms, one if you have a turbine; a second if you have infrastructure (such as a road or power line, but no turbine); and a third if you are within the project boundaries (without a turbine or any infrastructure).

Mr. Niezwaag reported that past North Dakota carbon dioxide legislative actions included a property tax break for DGC's carbon dioxide pipeline, rules for capture and storage of carbon dioxide, an oil extraction tax exemption for enhanced oil recovery, a tax credit for carbon dioxide capture (Don Boehm amendment), a sales tax incentive for carbon capture equipment, sales tax incentives for carbon dioxide compression, transportation and injection equipment, $5 million for research and development on new coal technology and increased coal conversation taxes for coal research and development.

Current North Dakota carbon dioxide efforts include trying to create a new Energy Technology Fund for research and development of projects like the Allam Cycle whether by earmarking a portion of the Legacy Fund earnings, maintaining and increasing coal conversion taxes or trying to move some county coal severance tax dollars.

Federal carbon dioxide efforts include working to get Department of Energy grants for new technology like the Allam Cycle and working to make Tax Code Section 45Q more useful by offering incentives for enhanced oil recovery with carbon dioxide.

Mr. Eggl then presented videos of the Touchstone Energy float in Mandan, North Dakota's Independence Day parade; an interview of Paul Sukut and Steve Johnson on the drivers impacting Basin Electric's rate increase and a local television station's report on the wind damage to DGC's under-construction urea storage building.

He then reviewed the agenda for the MAC to be held July 19-20 at The Lodge in Deadwood, South Dakota.

21. Human Resources Report

Senior Vice President–Human Resources Diane Paul reviewed the types of services that DGC's Medical Services can address and noted that Medical Services had 25,480 visits in 2014 and 28,450 in 2015, resulting in approximate savings that could total up to $4,754,584 in 2014 and $5,375,755 in 2015 (because our medical plan is self-funded). The annual employee dependent savings at headquarters alone is estimated to be approximately $35,300 annually. She spoke with Dr. Kaspari about how the medical program could be enhanced, and he suggested the possible installation of an MRI machine and physical therapy services. A cost/ benefit analysis is being done.

Workforce planning will be reviewed with the board in September.

Ms. Paul reported that the Cooperative has been without an apprenticeship agreement for a very long time and that Mr. Beiswanger has finalized that program in North Dakota and will do so in Wyoming next.

Director of Learning & Development/Safety Lynn Beiswanger reported on the new Infor Learning Management System, the "People.Power.Purpose." series, the "Power Plant/Transmission 101" class, the future supervisor education program "Growing Today our Leaders for Tomorrow", and the "Building Cooperative Connections" program.

A high-level overview of the Infor Learning management system will be done for the board this fall.

The next People.Power.Purpose. program will be broadcast live tomorrow at 2:00 p.m. from the marketing department trading floor on the work done in that locked-down area.

Mr. Beiswanger reviewed the Focus Card participation statistics. He noted that the "Our Power, My Safety" (**OPMS**) steering team meeting in June compared Basin Electric's Continuous Improvement Process to industry best practices and identified and analyzed gaps. The planning meeting in August will use this information to set the path for the OPMS process and train new OPMS Steering Team members.

22. Financial Services Report

A. 2016 Liability and Directors & Officers Insurance Renewal

Director of Risk & Insurance John Frank reviewed the existing coverage and limits of the casualty and Directors & Officers (**D&O**) insurance, which applies to Basin Electric and all subsidiaries. He then reviewed large losses that had occurred in the generation, transmission and chemical sectors from 2009 through 2015. He reviewed the D&O liability layering coverage totaling $100 million and the allegations that might trigger a D&O claim. In the interest of due diligence, he reviewed some optional quotes he had requested.

These insurances are due for renewal July 1, 2016. He noted that the premium for renewal of these policies was $3,183,205 compared to last year's premium of $3,250,096. He reviewed the coverages contained in the policies.

Two carriers, AEGIS and EIM, are mutual companies owned by their policyholders and both companies have announced a surplus distribution. Basin Electric's share of the AEGIS distribution is $83,615 and of the EIM distribution is $29,710.

Mr. Frank then reported that the exit of Great Britain from the European Union is a developing issue, so the ramifications to the United Kingdom are not yet known. There is likely to be some market turmoil in the near future and it may affect our direct placements and reinsurance. Staff will continue to monitor this matter to make sure that we do not have any issues with our placements that reside in London, Dublin, Bermuda and Switzerland.

Lloyd's of London CEO has stated he is confident that Lloyd's will stay in the center of global insurance and will maintain relationship with its European partners.

23. SPP Update

Mr. Christensen reported that that the SPP MOPC did not support SPP's staff recommendation that the Roundup-to-Kummer Ridge line be increased from 115 kV to

345 kW. This request next goes to the SPP board of directors. While possible, it is not likely that the SPP board would overturn the MOPC.

24. Engineering & Construction Report, continued

A. Sequestration Work with EERC/DOE.

Senior Vice President--Engineering & Construction Matt Greek reported that there are two FOA's (Funding Opportunity Availability) that have been issued by DOE for the first of a four-phase carbon capture and sequestration demonstration project. Applications are due by August 23, 2016.

One potential project site is the DFS where a Phase I proposal would be led by University of Wyoming's Carbon Management Institute. This would require a formal written commitment from Basin Electric to participate in the proposed project, including acknowledgement of any prior CCS-related business/research relationships. No cost share is required from Basin Electric. The signed letter is due before August 15, 2016.

Another potential project site is the AVS/DGC Synfuels Plant proposal led by the Energy & Environmental Research Center (**EERC**) for Phases I and II. This would require a formal written commitment to participate in the proposed projects with acknowledgement of any prior CCS-related business/research relationships; access to any existing technical and economic analysis of CCS implementation at AVS/DGC. The signed letter and cost-share commitment is due before August 15, 2016. Access to existing analyses is needed very soon.

Benefits to Basin Electric are the opportunity for future Department of Energy (**DOE**) research funding, potentially culminating in DOE funding of the storage component at AVS/Synfuels Plant and DFS; it gives the Cooperative an action plan to meet current and/or future carbon management requirements for existing and next-generation power production facilities; prefeasibility study for CCS at the DFS site; feasibility or prefeasibility study for CCS at the AVS/DGC site; and the advantage of applying to Phase II now is jumping to the front of the line for the Phase II DOE investment. Successful Phase I applicants will be competing for the remaining Phase II slots which remain after the August selections are made. If a project has enough working knowledge to apply for Phase II, it should do so at this time.

Participation in the Phase II FOA will require industry funding of about $2,000,000, while DOE will provide approximately $8,000,000 of funding for the Phase II work. Should the EERC/Basin proposal be accepted by DOE, Basin would be responsible for a letter of support and some portion of the $2,000,000 industry funding. EERC is actively seeking other industry partners to share in the $2,000,000 industry funding including the Lignite Energy Council.

25. Recess and Reconvention

At 4:52 p.m. President Peltier recessed the meeting until July 14, 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.

26. Roll Call

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

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

Said persons being all of the Directors of the Cooperative. Also present were Chief Executive Officer & General Manager Paul M. Sukut, Assistant Secretary Mark D. Foss and Basin Electric staff members Tracie Bettenhausen, Andy Buntrock, Eric Carufel, Tom Christensen, Tammy DeWitt, Ken Dolan, Mike Eggl, Elizabeth Erhardt, Matt Greek, John Jacobs, Steve Johnson, Becky Kern, Joe Leingang, Tom Leingang, Sharon Lipetzky, Tracy McBride, Darla Miller, Deb Olafson, Dave Raatz, Ken Rutter, Susan Sorensen, Katrina Wald, Valerie Weigel, Michelle Wiedrich, Roxanne Woeste and Mike Zimmerman.

Also present were DGC Vice President David J. Sauer and KEM/Mor-Gran-Sou/Roughrider co-managers Chris Baumgartner and Don Franklund.

27. Financial Services Report, continued

A. Authorization for Bank Account at KeyBank

Senior Vice President & Chief Financial Officer Steve Johnson recommended that the board approve opening a bank account at KeyBank. After discussion, it was moved by Director Pearson, seconded by Director Drost and carried that the following Resolution be adopted:

R09.07-12-16 RESOLVED, that KeyBank (the **Bank**) is hereby designated as a depository for the funds of the Cooperative and the officers and other persons of the Cooperative to open or continue an account or accounts with the Bank and to execute and deliver to said Bank signature card or cards supplied by the Bank containing specimen signatures of the officers and other persons hereinafter named, and that the officers and other persons hereinafter named are hereby authorized for and on behalf of the Cooperative to sign (either in original form or by facsimile), make, draw, accept, endorse or cause to be endorsed and to deposit or cause to be deposited in such account or accounts from time to time checks, notes, drafts, bills of exchange, acceptances, orders and other instruments for the payment of money to the Cooperative or withdrawal of funds held by the Cooperative;

RESOLVED, that the Bank is authorized to accept deposits to the account or accounts of the Cooperative and to pay, cash or otherwise honor or charge to the Cooperative any such instrument for the payment of money or withdrawal of funds held by the Cooperative when so signed (either in original form or by facsimile), made or drawn regardless of by whom or by what means the actual or purported facsimile signature or signatures thereon may have been affixed thereto if such facsimile signature or signatures resemble the facsimile specimens from time to time filed with the Bank by the Secretary-Treasurer or other officer of the Cooperative;

BE IT FURTHER RESOLVED, that checks, notes, drafts, bills of exchange, acceptances, orders and other withdrawal orders and any and all other directions and instrumentations of any character with respect to funds of the Cooperative now or hereafter with the Bank may be signed by any two persons holding the following offices or positions with the Cooperative: President, Vice-President, Secretary-Treasurer, Chief Executive Officer & General Manager and Senior Vice President and Chief Financial Officer, and the Bank is hereby fully authorized to pay, cash or otherwise honor or charge to such account or accounts any checks, notes, drafts, bills of exchange, acceptances, orders and other deposits or withdrawal orders so signed;

BE IT FURTHER RESOLVED, that any of the two persons then holding one of the offices or positions herein named and their designees (in writing) be, and they hereby are, authorized to give written or verbal instructions by telephone, telegraph, or otherwise, as they deem proper; and the Bank is authorized to accept instructions from any such persons herein named or their designee (in writing) as to the delivery of checks, notes, drafts, bills of exchange, acceptances, orders and other instruments for the payment of money or temporary investment of money from the account or accounts of the Cooperative; and any such person shall have the fullest authority at all times with reference to any transaction deemed by him to be proper to make or enter into for or on behalf of the Cooperative with the Bank. This paragraph shall be and remain in full force and effect until written notice of the revocation hereof shall be delivered to the Bank; and

BE IT FURTHER RESOLVED, that the following persons presently occupy the respective offices and positions designated in this resolution and that the same are duly qualified as such officials:

Wayne Peltier, President
Kermit Pearson, Vice President
Gary C. Drost, Secretary-Treasurer
Paul M. Sukut, Chief Executive Officer & General Manager
Steven P. Johnson, Senior Vice President
& Chief Financial Officer

BE IT FURTHER RESOLVED, that the Bank shall be entitled to rely upon a certified copy of these resolutions until written notice of modification or rescission has been furnished to and received by the Bank.

Interest Rates. Mr. Johnson presented and compared the May 2, 2016, June 1, 2016 and July 1, 2016, as well as the 2015 to 2016 U.S. Treasury Yield Curves from three months to 30 years, noting that U.S. 10-year and 30-year Treasury yields are at or near all-time lows. He reviewed negative interest rates on Swiss, German and Japanese government bonds.

RBC Capital Markets has stated that the British exit from the European Union "has introduced the very real possibility that this morphs into a domino effect across the region, so it will be a very long time before all of the potential volatility in Europe is behind us, which means we are likely to be well into 2017 before the Federal Reserve has a clear path to continue tightening even if the economy remains solid. Accordingly, we officially changed our Fed call and are now looking for the next hike to come in the third quarter of 2017 at the earliest. The one, and maybe only, factor we can see spooking the Fed into hiking rates at this point is an inflation scare. Though the extent to which inflation would need to rise to create such a scenario seems like a low probability event at present. Not that even with domestic-sensitive inflation running north of 3% y/y, the Fed has shown little concern in this regard. If the dollar strengthens materially from here, the rhetoric out of this Fed will undoubtedly be one that reiterates disinflationary risks."

Moody's Rating Review. Mr. Johnson reported that despite the implementation of a 7-mill rate increase, Moody's Investor Service (**Moody's**) had decreased Basin Electric's credit rating by two notches, but changed its outlook to stable. He noted that Moody's had been using a one-year-old financial forecast and associated data but unfortunately did not want to delay any further action past their standard 90-day review period.

Mr. Johnson reviewed the significant ongoing credit challenges and the related financing of DGC activities with Basin Electric's unsecured guarantee,

Mr. Johnson reviewed Moody's report with respect to its credit downgrade of Basin Electric and what we must do to improve that rating.

Messrs. Sukut and Johnson, Susan Sorensen, President Peltier and Vice President Pearson will present updates to Fitch, Standard & Poors (**S&P**) and Moody's and give an investor update the week of July 25.

What did we get from the 7-mill rate increase? The absence of a rate increase would have obviously led to financial performance that would have been even worse than projections so it helped stabilize the rating action. Without the rate increase, the rating may have stayed under review. Moody's stated "...the board is again demonstrating a willingness to increase wholesale power rates when necessary to boost financial performance."

Mr. Johnson reviewed historical credit spreads and noted we've seen an uptick in our commitment fees, draws on credit facilities and have had to post collateral, so the credit downgrade continues to have a financial impact. When we go to the markets in September or October, it will in all likelihood cost an additional 15 to 20 basis points.

Interest Rate Swaps. Mr. Johnson noted when these swaps were done, the ratings trigger was based upon the lower of the S&P or Moody's rating. He reviewed the history of the 2008 Series A Floating Rate Notes and associated swaps and noted that we are looking for alternatives.

B. Draft 10-Year Financial Forecast

Manager of Financial Planning & Forecasting Andrew Buntrock noted that the Ten-Year Financial Forecast would be presented this month and that approval would be requested at the August board meeting.

He reported that assumptions included a general inflation rate of 2.5%, no capital credit retirement, the revenue deferral would be zero by the end of 2016, there would be no dividends between entities, hedges would mirror accounting treatment, no Minnkota membership in Basin Electric and no CPP impacts. He then reviewed commodity price assumptions.

He reviewed Basin Electric's forecasted cost of service, revenues and member rates, the Basin Electric after-tax margin, capital requirements, capital expenditures cash flow, Basin Electric liquidity, cash balance, indenture equity, Margins for Interest requirement, and from a consolidated outlook, Moody's financial metrics including Times Interest Earned Ratio, Debt Service Coverage Ratio, Funds From Operation (FFO) to total debt ratio, FFO to interest ratio and equity to capitalization ratio.

C. <u>2017 Rate Schedule A</u>

Mr. Raatz introduced Rate & Load Analyst Elizabeth Erhardt, who reported that the 2017 Class A Rate component levels are based on the forecasted Class A Revenue requirement of $1.58 Billion when you consider the contract extension credit.

The draft 2017 Rate Schedule A rate components assumes that the board would approve the 2017-2026 Load Forecast, that the CPP would have no impacts and that there would be three new Montana members starting in October of 2017.

The 2017 fixed charge #1 assessment is $1,500 per Class A G&T member per month, $2,900 per non-Class A member per month and $4,400 per Class A distribution cooperative per month for a total of $4.7 million per year.

The fixed CROD demand and energy charges will be maintained at the current August to December 2016 levels and is forecasted to generate approximately $124.9 million.

Revenue adders are forecasted to generate a total of $11.7 million. She then reviewed the individual adders for each Class A member.

Ms. Erhardt then summarized the 2017 special rate levels and recommended the 34 mills/kWh electric/dual heat rate going into 2017. The interruptible Rate includes an energy rate of 34.12 mills/kWh and no demand charge during the months of March, April, May, Sept., and October. Special rates are forecasted to generate approximately $56.6 million in 2017.

The Base demand and energy charges will be maintained at the current August to December 2016 levels and is forecasted to generate approximately a total of $1,425.6 million.

The 2017 discount for contract extension results in a $40.2 million value to the membership, so the 2017 net rates for members with contract extensions are $21.77/kW and 28.32 mills/kWh for the Fixed CROD and $20.28/kW and or 33.24 mills/kWh for the Base Rates.

Additional modifications to Rate Schedule A include the implementation of a demand period waiver and the termination of the cap for member power cost. She reviewed the free demand period conclusion for 2017 with the intent to maintain this rate for at least five years. The 150% average mill-rate cap on Member Power Cost will be eliminated.

Ms. Erhardt noted that other applicable rates include the load management rate, distributed generation purchase rate, consumer energy purchase rate, solar pass-through rate and the renewable energy purchase rate.

The Load Management Rate is for distributed generation or load interruption excluded from the members' load management program that is 1 MW or larger in size. Basin Electric has the right to call up to 180 hours per season with a payment rate of $12/kW-season. The distributed generation energy payment will be indexed to NYMEX futures. The rate has a maximum five-year term.

The Distributed Generation Rate has no demand rate, an energy rate of 30.5 mills/kWh, a maximum term of five years, is for projects sized between 150 kW and 5 MW and has a 10 MW cap.

The Consumer Energy Rate is 27 mills with the rural electric cooperatives, is capped at 10 MW or 40,000 MWh and is for projects between 150 kW and 5 MW. The term is not to exceed five years (2021). The nameplate rating cannot exceed load. This rate is available to members only.

Dave Raatz stated the Solar Pass-through Rate is for loads no larger than 150 kW. Basin Electric will purchase 100% of the facility output at the member cost. The purchase is considered to be at the Basin Electric point of delivery. Basin Electric will bill the member facility output at member cost, exclusive of adders. This rate is capped at 7 MW.

The current Renewable Energy Purchase Rate is for member-owned or consumer-owned loads that are between 0 kW and 150 kW for purchases of 50 mills/kWh at the Basin Electric point of delivery. The demand and energy rates are zero. This rate is capped at 10 MW, with only 0.5 MW available. Two-thirds of the power currently sold under this rate includes solar projects.

The main focus is the Renewable Energy Purchase Rate which started with a 7 MW cap that was increased to 10 MW and was to provide a mechanism for members to support small renewable generation project development in their local region. It is for projects below 150 kW; Basin Electric purchases the facility output, so if it was a member-owned facility, Basin Electric would buy it. If the member puts generation in, Basin Electric would purchase the output for 50mill/kWh with no associated demand or energy behind the meter load billing. This rate can be for solar or wind.

Most applications came in within the last year or two. Most are on the eastern side of the service territory. The maximum commitment is currently about 9.5 MW. One member indicated that if it couldn't get on the Renewable Energy Purchase Rate, it would go with the solar pass-through rate. It was Mr. Raatz' opinion that the members need to be able to show that they have some solar power in their portfolios to help minimize the increase of legislative net metering obligations.

Based on market prices, Basin Electric's subsidy is about $260,000 per year. That amount should go down if market power prices go up because we've locked in the purchase price. Some resource commitments extend out 20 to 30 years. This topic generated a lot of discussion at the MAC, after which the MAC recommended that the current Renewable Energy Purchase Rate be maintained. The board expressed concern regarding the magnitude of the subsidy, our prior experience subsidizing wind projects and the June 18 FERC decision on the PURPA rate.

Mr. Raatz noted that cooperatives have been successful in avoiding some of the solar mandates which have been placed in the investor owned utilities.

The proposed concept for 2017 was to break the rate into a rate for 0-50 kW projects and a rate for 51-1000 kW projects, both with elimination of the 10 MW cap and both effective September 1, 2016. The rate for small projects would include a mechanism where if a consumer or distribution cooperative wanted to put a 40 kW solar project at their site, they could. Hopefully this would help fend off some requirements for net metering because it is typically driven by small consumers.

The rate for large projects over 50 kW would be for member or consumer owned projects and Basin Electric would purchase 100% of the facility output and considered a Basin Electric delivery point, so there would be no discount to the demand and energy purchase amounts. The payment rate would be equal to the applicable net Base Energy Rate for the applicable year. This rate would have no cap.

Mr. Raatz reviewed the current on-peak SPP market price forecast for 2017 through 2026, noting there is still some magnitude of subsidy but magnitude of subsidy would be significantly less. This would provide the membership with opportunities to help hold back some expansion of net metering requirements and provide the ability to take some edge off PURPA issues.

After discussion, the board reconfirmed its position that this Renewable Energy Purchase Rate should sunset for new applications at the end of 2016.

Rate Schedule A was presented for information only and action will be requested at the August board meeting.

D. Accounting Report

Senior Accounting Analyst Darla Miller reported that the June 2016 Statement of Operations reflected an estimated net margin of $19.8 million compared to the budgeted net deficit of ($6.3 million) for a favorable variance of $26.1 million. The net deficit last month was ($26.7 million) and for the same period last year was $7.5 million.

June member sales were approximately $2.3 million higher than budget. This includes the May actualization of $0.5 million. June sales are estimated to be $1.8 million more than originally forecasted. Member sales were higher due to weather. May sales to members were $91.1 million and for the same period last year were $101.0 million.

June surplus sales were $17.6 million compared to the budget of $14.1 million for a favorable variance of $3.5 million. May surplus sales were $5.3 million and for the same period last year were $21.5 million. Of the $15 million of deferred revenue from 2014, $7.5 million was brought in for June.

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

Basin Electric's June equity-to-asset ratio was 17.2% compared to 17.5% in May.

The June equity-to-capitalization ratio using the Moody's methodology (both without the consolidation entry for The Coteau Properties Company) was 20.7% compared to 21.2% in May.

The June equity-to-capitalization ratio based on indenture requirements for patronage distribution was 19.7% compared to 19.3% in May.

Mr. Peltier noted that he and Director Pearson would be participating in the rating agency trip later this month. The rotation of directors would resume for the December rating agency trip.

28. NRECA 2016 Region 6 Meeting Delegate and Alternate

Mr. Peltier reported that the 2016 NRECA Region 6 meeting will take place September 21-22 in Minneapolis, Minnesota and that a voting delegate and alternate should be named. After discussion, Mr. Peltier appointed Director Applegate to serve as voting delegate and Director Presser to serve as alternate to the NRECA 2016 Region 6 meeting.

29. Directors' Reports

Director Presser reported that he recently toured SaskPower's carbon capture facility at the Boundary Dam project. The carbon capture facility is a 20 to 25% parasitic load on the power unit and the injection well is 2.2 miles deep. SaskPower is not required to install over-fire air, SCR, SNCR or any mercury control equipment. The tour guide noted that the cost of electricity at his home was 13 cents.

Director Thiessen expressed his appreciation to the board and staff for their hospitality in hosting Upper Missouri at this meeting. He noted that it was time and effort well spent.

Director Gilbert reported that a 20 MW packing plant may locate in his area. It is still in the process of applying for permits and would employee 900 people at the start.

Director Drost reported that having the summer meeting in Bismarck had worked out well and that it should continue. Mr. Sukut estimated the cost savings over the 2015 summer meeting to be approximately $95,000.

30. Date and Time of Next Board Meeting

The next regularly scheduled meeting of the board of directors will take place August 9-11, 2016, at the headquarters building in Bismarck, North Dakota.

31. Adjournment

At 10:55 a.m., it was moved by Director Pearson and Seconded by Director Applegate that the meeting be adjourned. The motion carried.

Gary C. Drost
Secretary-Treasurer