Approved December 15, 2015

Basin Electric Power Cooperative
Bismarck, North Dakota

Minutes of the Regular Meeting of the Board of Directors
November 2-3, 2015

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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 Basin Electric's headquarters building, 1717 East Interstate Avenue, Bismarck, North Dakota, beginning on November 2, 2015 at 11:15 a.m. CST.

1. Call to Order

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

2. Roll Call

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

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

Said persons being all of the Directors of the Cooperative. Also present were CEO & General Manager Paul M. Sukut, Assistant Secretary Mark D. Foss and Basin Electric staff members Tracie Bettenhausen, Tammy DeWitt, Matt Greek, John Jacobs, Steve Johnson, Anine Lambert, Dave Raatz, Mike Risan, Ken Rutter, Susan Sorensen, Kevin Tschosik and Michelle Wiedrich.

3. Approval of the Agenda

The Directors considered the agenda for the conduct of the business of the meeting. After an opportunity for addition and deletion of items, the item "Business Practices Committee" was added to the agenda. It was then moved by Director Drost, seconded by Director Brekel and carried that the revised agenda be approved.

4. Approval of the Minutes

The minutes of the October 13-14, 2015 Regular Meeting of the Board of Directors, were presented and after an opportunity for corrections, it was moved by Director Gilbert, seconded by Director Rohrer and carried that the minutes be approved as revised.

5. General Manager's Report

General Manager Sukut reported that staff members of the Environmental Protection Agency (**EPA**) will be coming to North Dakota on Friday, November 13 for a meeting to discuss questions relating to a potential North Dakota State Implementation Plan. EPA has asked that the chief executive officer plus two employees from each generation organization attend. Dave Glatt from the North Dakota Health Department will also attend.

6. Western Fuels Update

Mr. Sukut reported on the Western Fuels meeting he and Director Baker attended last week. He noted that, as a result of the settlement with BNSF Railway Co. (**BNSF**), a budget with no rate increase was approved. Director Baker noted that coal nominations haven't varied much the last couple of years. BNSF has taken a proactive stance on its "take-or-pay" contracts with various other utilities. Mr. Sukut noted that Dairyland Power Cooperative (**Dairyland**) has stated that it is not sure if coal will be part of its future generation fleet. Generally, the tonnages coming out of the Powder River Basin continue to decrease.

7. Office of General Counsel Report

Mr. Foss reviewed legal matters concerning the Cooperative. He then reported on the purpose of the Business Practices Committee and its current members.

8. Operations Report

A. Monthly Operations Report

John Jacobs, Vice President of Operations, reported there were two minor Days Away Restricted or Transferred incidents in the past month. The accidents we have been experiencing have mostly been due to inattentive actions by the injured employee. To help resolve this issue personal accountability will be stressed. He reviewed the incident rate per year for each of the facilities.

He noted that eyewash and shower stations were being upgraded at the Antelope Valley Station (**AVS**) to increase the water temperature to the recommended level and ensure they are used properly when required. He noted short outages at the Dry Fork Station (**DFS**) to repair an induced draft fan linkage and to repair a superheater tube leak. He noted a forced outage at Laramie River Station (**LRS**) Unit #1 to repair an economizer tube leak. He also showed several slides of the new LRS warehouse.

Due to the early board meeting, generation numbers were not available.

9. 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 Drost continuing to keep the minutes.

10. Roll Call

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

Don Applegate
Leo Brekel
Arden Fuher
Mike McQuistion
Wayne Peltier
Allen Thiessen
Paul Baker
Gary C. Drost
Charlie Gilbert
Kermit Pearson
Roberta Rohrer

Said persons being all of the directors of the Cooperative. Also present were CEO and General Manager Paul M. Sukut, Assistant Secretary Mark D. Foss and staff members Tracie Bettenhausen, Andrew Buntrock, Eric Carufel, Tammy DeWitt, Matt Greek, Chad Heck, John Jacobs, Steve Johnson, Kerry Kaseman, Becky Kern, Mark Kinzler, Sharon Lipetzky, Sally Meier, Darla Miller, Curt Pearson, Dave Raatz, Mike Risan, Ken Rutter, Myron Steckler, Kevin Tschosik, Chris Vizenour and Michelle Wiedrich. Also present were David J. Sauer, Vice President of Dakota Gasification Company (**DGC**) and Alan Hopkins, staff member of Accenture.

11. Operations Report, continued

A. Distributed Generation Report

In response to an earlier question, Kevin Tschosik, Distributed Generation Manager, reported that distributed generation has its own 24/7 dispatch desk that works day-to-day with the Marketing & Asset Management Department. Because the Distributed Generation sites are not staffed 24/7, headquarters has taken over some duties: all engine starts and stops come from headquarters and when the Southwest Power Pool (**SPP**) dispatches a unit, headquarters does the derate. Melissa Wittenberg has done a really good job training the dispatchers for these new duties. The units have been responding well and there have been no complaints from SPP. The staff is adapting well, but they are a great deal busier.

He reported on the replacement of the lube oil cooler at Pioneer Generating Station and noted the different design with the fan speed adjusting to changes in the temperature. He discussed the replacement of the silencer at the Barber Creek Wyoming Distributed Generation site. He pointed out that weather has caused metal fatigue and there is a concern if the fibers in the silencer end up in the engine. Finally, he showed a slide of the insulation work that was done of the heat recovery steam generator tube penetrations at the Deer Creek Station (**DCS**).

October generation at the distributed facilities for the month was not available.

12. Marketing & Asset Management Report

A. Purchased Power and Non-Member Sales Report

Ken Rutter, Vice President - Marketing & Asset Management, reviewed 2016 pricing at the North Hub, Minnesota Hub and Palo Verde. Natural gas prices continue to drop based upon fundamentals. Gas generation surpassed coal generation in July. Storage injections are still resulting in bearish natural gas fundamentals as well. Within the Basin Electric load zone, the average day-ahead pricing was $18.64 and the average real-time price was $18.42. He reviewed wind versus real-time prices and noted that sometimes when wind prices go down, real-time prices go up.

As a net buyer in the SPP for the month of October, Basin Electric's purchase power price was better than anticipated. At the same time, when Basin Electric had surpluses, it realized less value than budgeted within SPP. As anticipated, there has been more value using the ties to move power from east to west.

Mr. Rutter discussed congestion management and reviewed generation-to-load congestion spreads and congestion hedges.

We've learned that AVS and Leland Olds Station paths were highly valuable paths as Auction Revenue Rights (**ARR**); there is very low congestion between base-load generation and load, thus Transmission Congestion Rights (**TCR**) are not providing much credit. Some wind paths and some waste heat paths were liabilities as ARRs as the Auction Clearing Price (**ACP**) was negative; and LRS #1 and Stegall purchased paths added value (the purchase price was $1.50 versus the actual congestion price of $2.15).

Net overall for October, Basin Electric will incur congestion charges between generation and load in excess (estimated at $365,000) of the value of the hedges. With some actual marketing data, Marketing believes it can manage this to a flat position for November.

The November strategy will be to analyze the October results and self-convert liability paths and hold paths as ARRs if the ACP exceeds incurred congestion. Of total November allocations, approximately 75% will be self-converted to TCRs and 25% were held as ARRs.

The first round November results were very similar to October. November ACPs for baseload were not as high as October, but were still positive ($0.34 on peak down from $1.82). We bid $1.75 for LRS, which cleared at $2.06 (we bid $2.17 in the second round). We bid $1.50 for Stegall, which cleared at $1.95. (We bid $1.75 in the second round.) ARR revenue after Round #1 was approximately $60,000.

He then reported on ancillary services. With respect to Spin and Supplemental (non-spin), SPP load pays for roughly 90 MW. Thus far, we have self-provided roughly 90% of the load requirements. For 2016, we budgeted self-providing 75% of our needs. With respect to regulation, SPP load pays for roughly 1% of the demand. Thus far, we have self-provided over 200% of our needs. For 2016, we budgeted self-providing 90% of our needs.

Regulation Service is the use of regulation-up and regulation-down through automated generation control equipment to automatically and continuously adjust resource output to balance the SPP Balancing Authority Area in accordance with North American Electric Reliability Council (**NERC**) control performance criteria. This response is to four-second setpoints set by SPP. Spin Reserve is the unloaded generation that is synchronized to the system and ready to serve additional demand. Supplemental generation is not connected to the system but capable of serving demand within a specified time. It is typically provided by quick-start units that can respond within 10 minutes. Total ancillary service revenue was $229,000 for Regulation Up/Down; $150,000 for Spin Reserve; and $1,100 for Supplemental Generation for a total of $380,100. Marketing needs to continue working with the plants to determine appropriate costs to offer these ancillary services into the market.

With respect to SPP Generation Deviation Charges, Mr. Rutter noted that the eight main causes of a residual unit commitment (**RUC**) penalty are: unrestricted resource deviation; deviation from day-ahead minimum in real time; deviation from day-ahead maximum in real time; deviation from day-ahead due to outage; deviation from RUC Scheduled, not cleared in day-ahead, received RUC award but did not produce; deviation from RUC commitment; deviation from status; and deviation from net. Real-time Regulation Non-Performance is the amount charged for failure to provide regulation deployment. Contingency Reserve Deployment Failure is the amount charged for failure to provide contingency reserve, spin and supplemental product. Through October 27, Basin Electric has incurred approximately $45,000 in market deviation charges, $27,000 of RUC penalties, $18,000 of real-time regulation non-performance penalties and $500 in Contingency Reserve Deployment failure penalties. Marketing budgeted $2 million for 2016 total deviation charges or approximately $166,000 per month. Mr. Rutter said that SPP has been impressed with Basin Electric's generating units' ability to respond.

Mr. Rutter then reported that on the Eastern System, in total, SPP energy for the month was very near the budget. Midwest Independent System Operator (**MISO**) energy loads are projected to be approximately 5% higher than budget. Forecasted cool temperatures projected SPP loads to peak between October 29-31.

In the West, loads continue to be well below budget. Central Montana loads were also well under budget.

He reviewed the Cooperative family's current transportation assets and reported that Marketing manages transportation assets with a value of $175 million. He discussed cross-company asset management, which includes customer service and product scheduling, railcar tracking, railcar fleet management, rail rate management, inventory management, rail maintenance (eight-mile stretch of track), certified shipments and dispatch, rail fuel surcharge management and trucking relationship management.

The marketing group is looking for entity-wide logistics synergies that can further facilitate DGC sales efforts by allowing Basin Electric, DGC and Dakota Coal Company sales & marketing personnel to work on revenue enhancement while reducing overall transportation expenses. The goal of revenue enhancement/expense savings is $5 million. He said they hope to have an overall plan ready by mid-December.

13. <u>Cooperative Planning Report</u>

Dave Raatz, Vice President of Cooperative Planning, reviewed the status of contract extensions with the members. Both Federated Rural Electric Association and L&O Power Cooperative (**L&O**) have indicated they will execute their contract amendments.

Minnesota Valley Electric Cooperative (**MVEC**) indicated it would not sign the extended contract; however, there may be more discussion. A lot of their discussions revolved around whether it would be in their best interest to have a single power supplier or two. We have not heard from Wright -Hennepin Cooperative Electric Association (**Wright-Hennepin**). We don't anticipate they will sign the extended contract as they want to do a lot with solar generation and keep their options open. These two existing contracts (MVEC and Wright-Hennepin) go through 2050.

The Western Area Power Administration (**Western**) does not want to change its delivery point into SPP as Western would experience a nearly $1 million cost increase. Basin Electric and the membership have offered to make Western whole. The main issue for Basin Electric and the membership is that when Western power has to be scheduled on a day-ahead basis in MISO, from an accreditation or resource adequacy perspective, MISO will only allow the minimum schedule of the Western power to serve as a basis for power pool accreditation. Basin Electric would have to come up with approximately 20 MW of additional resources to support the federal power delivery. We've indicated to the members that the wholesale power contract says we provide total load minus the usable Western power. So we'd bill the Basin Electric members for this 20 MW of additional usage at the Cooperative's Class A demand rate.

Western would like to have all the preference customers work with MISO to try to resolve the issue. This would require a MISO tariff modification, which staff thinks is a long shot. Staff believes Western should allow the federal points of delivery to be changed in the contract amendment exhibits.

Western cannot comply with the regional transmission organization's "must offer" provision and that's where they're losing their accreditation in the MISO system. Those aren't the rules in SPP regarding hydro allocation/generation. Basin Electric staff developed and distributed a white paper to the Manager's Advisory Committee (**MAC**). Central Power Electric Cooperative (**Central Power**) and East River Electric Power Cooperative (**East River**) said they understand the issue and Basin Electric's position. This is a huge issue for Mor-Gran-Sou Electric Cooperative and KEM Electric Cooperative, whose Western allocations are a very large percentage of their loads and they have lot of load in the MISO footprint. Staff will continue discussions with Western.

The current Tri-State G&T Association (**Tri-State**) contract includes all-requirements agreements for all of Nebraska load on the eastern and western electrical system and a Fixed Contract Rate of Delivery (**CROD**) of 225 MW for the Colorado and Wyoming load. The concept is to make this an all-requirements contract on the east side and all west-side deliveries would go under the Fixed CROD. Staff started getting involved in the details last July. A couple options have been presented to Tri-State. In accordance with the Board's direction, the extension of the contract through 2075 is a priority. We offered to change some delivery points, as well as pick up the Western Area Colorado Missouri (**WACM**) transmission, but only if Basin Electric becomes the transmission customer under the WACM tariff.

Based on current board policy, for Basin Electric to pick up the extra transmission expense consistent with rest of members, we would need the 2075 contract extension.

Regarding the West Side, Basin Electric sent a letter to Tri-State with three options: (1) maintain the current contract through 2050, at a fixed CROD; (2) same 225 MW fixed CROD, but extending through 2075; or (3) offer an enhanced CROD and same delivery arrangement.

Since the last board meeting, we sent a second letter to Antelope Hills Project as they were largely nonresponsive in their response to our first letter. Our second letter was more pointed. We had a conference call on October 29 that went well. By this week Friday, the Antelope Hills people will provide a timeline tying their project financing with construction schedules. Mr. Raatz doesn't think they can make the contract commercial operation date of June 2016, Another call is scheduled in 10 days. Under current tax law, they need to be commercial by the end of 2016 to get production tax credits (**PTC**). There are liquidated damages for not meeting the commercial operation date. By year-end 2016, we'd have gotten more than $4 million back. Ultimately, the question is whether this will be built or not.

Last month, we also talked about the possibility of an additional 650 to 700 MW of new wind. This would be very important if the Clean Power Plan (**CPP**) goes forward. This is just a fraction of the new wind we would need. There is currently upwards of 1500 MW available on the east side. We have executed a contract with NextEra for Brady II; however, this contract is contingent on each party notifying the other of its election to proceed prior to year's end or the contract automatically terminates.

In addition, staff is looking at other potential wind options that could go commercial in calendar 2016 in order to take advantage of PTCs. Staff hopes to be in a position to have discussions with the board in December. Some contracts look very favorable. One positive thing we've heard is the possibility that PTCs will be extended for an additional two years. That would take some pressure off this project.

The Rate Subcommittee is scheduled to meet for a full day on November 16, 2015. Main topics are the general rate structure, special rates, solar generation and load management options. Staff is putting together documentation to share with the committee. General rate structure, load management, and solar are the three biggest issues. With the volatility of coal and oil loads, should we pursue solar generation? We are getting many requests for 1 MW wind projects.

With respect to load management, the real question is do we try to change when we do load management from the time of member peak to the regional transmission organization (**RTO**) peak? This brings up the question of coincident billing. We are dealing with four different power pools. We need to focus on how we get the biggest reduction in cost. Obviously, there would be both winners and losers. The question then is how fast we should move forward with it.

Director Thiessen asked whether we gave up rights to the Miles City DC Tie. Mr. Raatz responded that we surrendered 60 MW and that both the Rapid City and Stegall Ties have the ability to move power into the Wyoming market. That is a different market than using the Miles City DC Tie. We see huge price differentials at both Stegall and Rapid City. Most of the power taken from east to west to take advantage of market price differential goes through Stegall. As we look at Stegall and Rapid City, we have significant load and generation on both sides of the DC ties which integrate into the Basin Electric system.

We have no generation in Montana on the west side. Now that our relationship is different with Western, we're finding it difficult to provide spinning reserves. Also because DC tie capability was so much higher than load on the west, we'd have to convert it to point to point service and would be subject to regional cost assessments in an RTO. This path was getting very expensive. It's not that we want to give it up, it's just not economical to reserve all of the Miles City DC Tie and as a result, we have retained two-thirds of it.

Mr. Rutter noted that if we build 100 MW of generation in Montana, we'll have more than enough capability to serve the load.

Stegall is of most value east to west right now. Mr. Raatz noted that at some point in the near future, we will have to perform some major maintenance on the Stegall facility, at an estimated cost of approximately $50 million. It was built in 1980. It uses old technology. We are postponing this work until we understand the implications of the CPP on west-side generation. Under some scenarios, a significant transfer capability on those ties will not be needed.

A. Northern Tier Energy Center

Mr. Raatz provided an update on the timeline provided in September. Toward the end of February 2016, the potential Northern Tier Energy Center (**NTEC**) partners, the Cooperative, Minnesota Power Company (**MPC**) and Dairyland must nominate how much, if any, of this power plant each will own. Staff continues to think Basin Electric should nominate approximately 350 MW. Submission of the nomination will commit Basin Electric to an additional $1 million contribution. Execution of the definitive agreements would take place during the second quarter of 2016 and would require an additional commitment of approximately $300 million.

Currently, the plan is that a detailed project update will be provided in January or February, a final power nomination will be requested in February and final authorization for the entire project will be requested in April.

Since September, staff continues work on the definitive agreements. During the November 24 CEO meeting, staff will provide a detailed project update and request that the CEOs execute a nonbinding term sheet. Key provisions of the term sheet are a management committee, foundational items, owners' rights, financial capability, payments and defaults, transfer restrictions, construction and operating agent, insurance, term and decommissioning.

Director Pearson expressed concern as to whether Wisconsin is the best site given the CPP. Mr. Raatz noted that 30-plus sites in North Dakota, Minnesota, Iowa and Wisconsin were studied and ultimately, from an economic perspective, the Wisconsin site is the best option. Key to this site is that it has two to three different adjacent pipelines; it is next to a propane storage facility; and it has good industrial acceptance by the local communities.

He noted that you bid your price into MISO and prices are higher in Wisconsin than in North Dakota. If Wisconsin adopts a rate-based limit under the CPP, it meets all criteria, but what if the state of Wisconsin goes to mass-based limit? What is our ability to say we'd get an allocation in the state of Wisconsin? We've already told MPC that we want to discuss this. There is another meeting of the staffs on November 12-13 and this is a topic to be discussed at the CEO meeting on November 24. We've all signed confidentiality agreements and the state of Wisconsin hasn't yet been approached because of the confidentiality agreements. Mr. Raatz noted this can't wait long as we still have load growth and power requirements to meet. We've looked at another unit at DCS, but that facility is adjacent to the Buffalo Ridge Wind Project and when you look at locational margin prices, that creates a problem. Basin Electric also continues to worry about the reserve margin in MISO.

Mr. Raatz recommended the CEO be authorized to enter into a nonbinding term sheet to support the development of the NTEC definitive agreements. After discussion, it was moved by Director Drost, seconded by Director Baker and carried that the following Resolution be adopted:

R01.11-02-15 RESOLVED, that the CEO & General Manager, or his designee, be authorized to enter into a non-binding term sheet to support the development of Definitive Agreements related to the Northern Tier Energy Center project.

14. Engineering & Construction Report

A. Project Funding Chart

Mr. Greek reported that no action items would be presented for approval this month. He then presented the list of major projects including the approved budget amounts, total amounts committed and completion dates. The Dry Creek Substation was energized during the month with no issues.

15. Transmission Report

Mike Risan, Senior Vice President - Transmission, reported on the SPP annual meeting held near the end of October. The general tone of the meeting was very positive and welcoming with respect to our October 1 integration into SPP. Bob Harris of Western and he were invited to participate in the evening event celebrating the integration of the IS into SPP. Brian Kalk and several state officials from the Basin Electric region attended the Regional State Committee meeting as well.

He noted that settlement discussions with Montana-Dakota Utilities Co. (**MDU**) and lease discussions with our members are still on track. Authorization to execute new member leases and to terminate the Interconnection & Common Use Agreement with MDU will be requested next month.

Discussions with Otter Tail Power Company (**OTP**) are much improved. Tentative understanding has been reached on reciprocal tariff service. The parties are also exploring the option of a mini-ITA concept for the OTP/Central Power agreement to avoid pancaked tariff service.

In a parallel effort, on May 22, 2015, Basin Electric made a separate filing for the facilities and associated Annual Transmission Revenue Requirement (**ATRR**) in SPP for 2015. Some parties filed interventions and submitted data requests. We provided responses prior to the October 30, 2015 due date. There is a technical conference on November 16. The Federal Energy Regulatory Commission (**FERC**) settlement conference has been scheduled for December 2, 2015 in Washington, DC. To date, there has been no FERC order but in the meantime, Basin Electric must proceed with the annual update process for 2016. There is a third process for that as well. The September 30, 2015 Protocols require a 2016 estimate for transmission costs. On October 28, 2015, Basin Electric posted the annual update so interested parties could ask questions. Missouri River Energy Services, Western and Heartland Consumers Power District participated. We assume the AVS-to-Judson line will be in service and that we will start to recover costs from SPP in the May time frame. No significant negative comments were received. This is another good sign on this cost recovery concept.

We have been involved in a number of other ATRR settlement discussions with parties in the Upper Missouri Zone. There has been a great deal of activity regarding the initial filings to join SPP.

With respect to the Bakken, staff continues the process of updating the operating guide for winter 2015-2016. Last year, the maximum load serving capability in the Williston Load Pocket was approximately 1,100 MW. This year, having the AVS-to-Charlie Creek and the Charlie Creek-to-Judson lines in service will provide additional transmission capacity into the area. The peak load in the Bakken last winter was 840 MW.

Regarding the transmission planning process, we previously identified the AVS-to-Judson-to-Neset line and the North Killdeer Loop project in the IS transmission planning process. We have endorsement from SPP to construct the AVS-to-Neset project and staff is working through the SPP planning process to receive a similar notice to construct for the North Killdeer Loop project.

In the SPP planning process various transmission system contingencies are run to generate a deficiency list. In the Bakken area a number of deficiencies north and south of Lake Sakakawea were identified, which indicate the next soft spot requiring reinforcement is north of Lake Sakakawea (assuming the North Killdeer Loop fixes the issues south of Lake Sakakawea). Once the deficiency list was identified, we offered Detailed Project Proposals to resolve those issues and for the North Killdeer Loop. We cautiously anticipate that SPP will accept our proposal as the best solution and will authorize Basin Electric to build the North Killdeer Loop, as it would then be eligible for cost sharing.

SPP will evaluate all submitted proposals however. We expect that SPP will select projects in the April time frame. Longer-term projects (needed beyond three years) are eligible for competitive bidding and the request for proposal process requires a staff review followed by an "industry expert panel" evaluation of the proposals on independent basis. The time frame for that process is about one year. We believe the facility upgrades in the Bakken are needed within the next three years, so we would not expect competitive bidding.

Basin Electric received notice of a potential $75,000 fine as a result of a violation on its self-certified facility review from the Midwest Reliability Organization (**MRO**) Region. We responded, proposing a draft settlement where we reallocate those penalty dollars to our internal compliance program. MRO acknowledged receipt of our response and will reply in several weeks.

Basin Electric made a presentation on the NERC registration process at a recent MAC meeting, during which it was suggested that some of our larger members which are heavily involved in the NERC process should register their own facilities with NERC. These members were generally in agreement. Outreach meetings have been scheduled.

Basin Electric hosted a compliance workshop on October 26-27. We will also host FERC Standards of Conduct training later this month. We've not heard from enforcement staff with respect to the recent Western Electricity Coordinating Council audit. This process could take a year.

With respect to joint tariff and market development discussions in the Western Interconnection, a meeting has been scheduled with Joel Bladow from Tri-State to discuss and plan next steps.

16. Communications & Administration Report

Mike Eggl, Senior Vice President-Communications & Administration, presented photographs and discussed the Integrated Test Center (**ITC**) announcement at DFS by Wyoming Governor Mead, Powder River Energy Corporation manager Mike Easley and Mr. Sukut on October 8, 2015.

He then reported that the board policy on renewable resource obligations was presented and discussed at the October 22 MAC meeting. The next board policies to be reviewed (in January of 2016) are #03, Chief Executive Officer & General Manager Continuity of Leadership; #04, Compliance with Sections 201 and 210 of the Public Utilities Regulatory Policies Act of 1978 (PURPA) and #05, Manager's Advisory Committee.

He noted that the Resolutions Committee had combined Basin Electric's Mission and Vision Statements as part of their review of the Statement of Ideals and Objectives.

A. Information Systems & Technology Report

Mark Kinzler, Vice President & Chief Information Officer, reported on Information Systems & Technology (**IS&T**) activities with respect to joining SPP, the NERC Critical Infrastructure Program (**CIP**), platform consolidation, planning, software and hardware, governance and "Minding the Store". The major project this past year was the SPP integration project, which went live on October 1, 2015. IS&T continues to follow-up on the interfaces. He noted that IS&T has worked on the NERC CIP for two years. The Transmission Department has also been heavily involved. IS&T is working to have policies and workflows in place by year-end and will perform a gap analysis in January/February of 2016. The required program date is April 1, 2016.

With respect to platform consolidation, IS&T is focusing on upgrading the Windows 2003 operating systems. Thirty-one servers remain. The additional cost to continue support over and above Microsoft's normal support in 2016 is $825,000. The Windows SQL 2005 database is in a similar support situation.

A request for information will be sent to potential vendors next week for the Enterprise Asset Management software review. A health check on the current system has been completed. Documentation on existing interfaces and customizations has been completed.

IS&T contracted with DataLink to assist with developing a template for a business continuity plan. This effort is a partnership between the business units and IS&T. The project is much more expansive than data recovery; it's how to continue business should the headquarters building be destroyed. It identifies types of risks which are divided into three areas: crisis management, business continuity and information technology disaster recovery.

Programming is complete and communications have been established to all substations for the Upper Missouri Power Cooperative (**Upper Missouri**) supervisory control and data acquisition project.

Mr. Kinzler then introduced Alan Hopkins with Accenture, who provided a recap of the SPP Integration Program project.

Director Drost expressed the Board's appreciation for all the work done by so many employees on the SPP Integration Project.

17. Recess and Reconvention

At 4:15 p.m., President Peltier recessed the meeting until 9:00 a.m. on November 3, 2015, at which time the meeting reconvened with President Peltier continuing to preside and Secretary Drost continuing to keep the minutes.

18. Roll Call

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

Don Applegate	Paul Baker
Leo Brekel	Gary C. Drost
Arden Fuher	Charlie Gilbert
Mike McQuistion	Kermit Pearson
Wayne Peltier	Roberta Rohrer
Allen Thiessen	

Said persons being all of the directors of the Cooperative. Also present were CEO and General Manager Paul M. Sukut, Assistant Secretary Mark D. Foss and staff members Lynn Beiswanger, Tracie Bettenhausen, Andrew Buntrock, Eric Carufel, Ted Cash, Tammy DeWitt, Christy Dirk-Senn, Matt Greek, Deb Haga, Steve Johnson, Matt Kolling, Faye Miller, Diane Paul, Dave Raatz, Mike Risan, Susan Sorensen, Bill Stafford, Steve Tomac and Michelle Wiedrich. Also present was Minnesota Valley Cooperative Light & Power manager Pat Carruth.

19. Human Resources & Development Report

Diane Paul, Senior Vice President-Human Resources & Development, provided an update on Employee Guidelines that have been revised: Substance Abuse Program/Drug Testing; Cell Phone Recording Policy; Vacation policy for employees planning to retire; bereavement leave; and military service pay. She then reported on United Way activities, noting that, to date, Basin Electric employees have contributed $121,550, not including the Basin Electric match or other fundraisers at Basin Electric.

She reported that Lynn Beiswanger, Director of Learning & Development, hired a new learning and development administrator for the Wyoming facilities.

Mr. Beiswanger then reviewed the 2016 Comprehensive Learning & Development Cooperative Plan: (1) develop in-house educational opportunities; (2) develop a new orientation program; (3) implement talent management cooperative-wide; (4) develop a comprehensive apprenticeship program for all Basin Electric facilities (in partnership with Bismarck State College and the National Energy Center of Excellence); (5) implement the Infor Learning Management System; and (6) institute a job shadow program between departments within Basin Electric and the membership.

He discussed a program he would like to establish called The Power of Connections - Building on the Cooperative Spirit Program which would: (1) establish a team to visit with member cooperatives; (2) include a vetting and training process; (3) the team visits a member cooperative, observe field personnel and be introduced to a farmer/rancher member selected by the member cooperative; (4) the member cooperative visits Basin Electric headquarters to meet with the senior management team and observe the construction team and departments and visits/tours a power plant, substation, transmission, distributive generation and wind turbines.

Ms. Paul noted that the 401(K) Investment Committee was established in February of 2007 with the Chief Financial Officer as chair. Steve Johnson, Senior Vice President & CFO, then reviewed the Investment Charter of the 401(K) Investment Committee, which states "The Committee shall hold regular annual meetings or shall meet more frequently as circumstances require. The Committee shall keep minutes of the meetings and provide reports to the Board." Over the last couple years, the group has met twice a year with representatives of Vanguard to discuss different aspects of the plan. Going forward, regular reports will be given to the board.

The agenda at the October 1, 2015 Investment Committee included economic and market outlook, investment performance returns, state of the plan, plan and participant statistics, education updates and a pricing discussion. He then presented the Plan summaries and noted that the Basin Electric/DGC employee participation rate is between 97%-98%.

20. Financial Services Report

Mr. Johnson reported that in 2010, EB-5 funds were borrowed through a program administered by the state of South Dakota in eight separate draws totaling $105 million and were used to partially finance construction of the Deer Creek Station. The term of these notes was five years and the interest rate was 2.50%. The final payment on these notes was made on October 26, 2015.

Mr. Johnson reviewed projected liquidity from September 2015 to September 2016, which includes $100 million of funds in the Member Investment Program and assumes a $475 million debt issuance in April of 2016.

He noted that Basin Electric could borrow monies now in lieu of entering into an interest rate hedge. The current terms of borrowing $100 million from CoBank, ACB (**CoBank**) are a 15.4-year average life, semi-annual principal and interest payments at an indicative gross coupon of 4.48% with patronage of 0.75% for a net coupon of 3.73%. CoBank has a maximum hold that they are close to reaching with respect to Basin Electric; however, a waiver could be granted.

The indicative terms of borrowing $100 million from the Farm Credit System are a 15.4 average life, semi-annual principal and interest payments at a gross coupon of 4.86% with patronage of 0.50% with a net coupon of 4.36%.

He compared these terms to the expected terms of a public market borrowing of $400 million with a 30-year bullet payment and semi-annual interest at the 30-year Treasury rate of 2.88% with a 1.75% credit spread resulting in a 4.63% coupon as well as borrowing $400 million with a 20-year average life with semi-annual principal and interest payments at the 30-Year Treasury rate of 2.88% with a 1.60% credit spread, an amortizing premium of 0.20% and a 4.68% coupon.

Mr. Johnson noted that a group of staff and directors will meet with Goldman Sachs and Fitch Ratings on December 2, with Standard & Poors Ratings Service and Moody's Investor Services on December 3 and with a number of banks on December 4.

A. Draft 2016 Operating and Capital Budgets

Andrew Buntrock, Manager of Financial Planning & Forecasting, reviewed the 2016 Operating Budget, noting the changes between the financial forecast and the budget. He reviewed the projected 2016 margin, cost of service, annual revenue requirements and financial metrics. Mr. Buntrock then reviewed the 2016 capital budget.

He noted that final Operating and Capital Budgets would be presented for approval at the December board meeting.

B. First Amendment to PWND Loan Agreement

Matt Kolling, Senior Staff Attorney, reported that Basin Electric and PrairieWinds ND 1, Inc. (**PWND**) entered into a Loan Agreement in July 2011. The Loan Agreement requires that PWND make payments on the loan on a quarterly basis, consistent with the Cooperative's quarterly payments under its Rural Utilities Service (**RUS**) loan obligations.

Now that the RUS obligations have been replaced with private placement financing, Basin Electric no longer makes quarterly payments. The private placement payments are instead set up on a semi-annual basis, with payments being made in June and December each year.

Mr. Kolling recommended that the Loan Agreement be amended to allow for semi-annual payments rather than quarterly payments and that a replacement note be issued from PWND to Basin Electric to reflect the change in the payment schedule. All other terms of the Loan Agreement and note, including the interest rate and term of repayment, would remain the same.

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

R02.11-02-15 RESOLVED, that the Board of Directors approves changing the payment schedule on the loan between Basin Electric Power Cooperative (the **Cooperative**) and PrairieWinds ND 1, Inc. (**PWND**), from quarterly payments to semi-annual payments; and

BE IT FURTHER RESOLVED, that the CEO and General Manager, or his designee, is authorized to execute the First Amendment to Loan Agreement between the Cooperative and PWND and to accept the restated note from PWND.

C. Second Amendment to PWSD Loan Agreement

Mr. Kolling reported that Basin Electric and PrairieWinds SD 1, Inc. (**PWSD**) entered into a Loan Agreement in July 2011. The Loan Agreement requires that PWSD make payments on the loan on a quarterly basis, consistent with the Cooperative's quarterly payments under its RUS loan obligations.

Now that the RUS obligations have been replaced with private placement financing, Basin Electric no longer makes quarterly payments. The private placement payments are instead set up on a semi-annual basis, with payments being made in June and December each year.

Mr. Kolling recommended that the Loan Agreement be amended to allow for semi-annual payments rather than quarterly payments and that a replacement note be issued from PWSD to Basin Electric to reflect the change in the payment schedule. All other terms of the Loan Agreement and note, including the interest rate and term of repayment, would remain the same. This Loan Agreement was amended once previously, in November 2012, in order to change the interest rate on the loan. Accordingly, this would be the Second Amendment to the Loan Agreement.

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

R03.11-02-15 RESOLVED, that the Board of Directors approves changing the payment schedule on the loan between Basin Electric Power Cooperative (the **Cooperative**) and PrairieWinds SD 1, Inc. (**PWSD**), from quarterly payments to semi-annual payments; and

BE IT FURTHER RESOLVED, that the CEO and General Manager, or his designee, is authorized to execute the Second Amendment to Loan Agreement between the Cooperative and PWSD and to accept the restated note from PWSD.

21. Voting Delegate & Alternate to 2015 Mid-West Electric Consumers Association Annual Meeting

Mr. Peltier noted that a delegate and alternate are needed to attend the 2015 Mid-West Electric Consumers Association annual meeting. Last year, director Thiessen was the delegate and director Drost was the alternate. After discussion, it was moved by Director Pearson and seconded by Director Gilbert that Directors Thiessen and Drost serve as voting delegate and alternate, respectively. The motion carried.

22. Directors' Reports

Director Baker wished Director Fuher the best.

Director Thiessen reported Upper Missouri is meeting today and tomorrow. He thanked Basin Electric staff for making presentations during the Upper Missouri meeting.

Director Brekel reported Tri-State was sued for the Jemez Mountains fire in New Mexico. Last Wednesday, the jury found that Tri-State was 20% negligent, despite the fact that the electricity had passed the meter. Evidently the jury viewed Tri-State as having deep pockets. Tri-State is considering an appeal.

Director Applegate thanked Mr. Sukut for participating in Northwest Iowa Power Cooperative's annual meeting. The EPA Section 111d issue was discussed extensively.

Director Drost thanked Director Fuher for his service. He then invited the directors and senior staff to L&O's hospitality room during annual meeting.

Director Fuher expressed his gratitude for being allowed to work with the board and Basin Electric.

Director Peltier thanked Director Fuher for his service and being so cooperative-minded. He then invited directors and senior staff to District 9's hospitality room during annual meeting.

23. Date and Place of Next Board Meeting

The next regularly scheduled meeting of the Board of Directors will take place December 14-17, 2015, at Basin Electric's headquarters building in Bismarck, North Dakota.

24. Executive Session

At 10:25 a.m., it was moved by Director Applegate, seconded by Director McQuistion and carried that the Board retire into executive session to discuss Human Resources matters. At 10:30 a.m., it was moved by Director Fuher, seconded by Director Gilbert and carried that the Board arise from executive session.

25. Adjournment

At 10:30 a.m., Director Fuher moved to adjourn the meeting, which was seconded by Director Thiessen and carried.

Gary C. Drost
Secretary-Treasurer