Approved March 10, 2015

Basin Electric Power Cooperative
Bismarck, North Dakota

Minutes of the Regular Meeting of the Board of Directors
February 10-11, 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 the headquarters Building, Bismarck, North Dakota, beginning on February 10, 2015 at 8:00 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 Claire M. Olson and Basin Electric staff members Jamey Backus, Robert J. Bartosh, Tracie Bettenhausen, Andrea Blowers, Andrew Buntrock, Tom Christensen, Shawn Deisz, Tammy DeWitt, Mike Eggl, Mark D. Foss, Robert Frank, Matt Greek, Dan Hagel, John Jacobs, Steve Johnson, Becky Kern, Janet Kubisiak, Rod Kuhn, Deborah Levchak, Sharon Lipetzky, Jay Lundstrom, Gavin McCollam, Cris Miller, Deb Olafson, Dave Raatz, Mike Risan, Ken Rutter, Susan Sorensen, Shanda Traiser, Kevin Tschosik, Valerie Weigel and Michelle Wiedrich.

   Also present were Dakota Gasification Company (**DGC**) director Alan Klein, DGC Vice President and Chief Operating Officer David J. Sauer, East River Electric Power Cooperative (**East River**) director Ken Gillaspie and Mor-Gran-Sou Power Cooperative (**Mor-Gran-Sou**) director Casey Wells. DGC director Tom Owens was present via conference call for the PIRA Energy Group (**PIRA**) commodity fundamental price outlook presentation.

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, it was moved by Director Drost, seconded by Director Gilbert and carried that the agenda be approved as presented.

4. **Approval of the Minutes**

   The minutes of the January 13-15, 2015 Regular Meeting of the Board of Directors were presented and after an opportunity for corrections, it was moved by Director Rohrer, seconded by Director Pearson and carried that the minutes be approved as presented.

The minutes of the November 6/December 7, 2014 Board Reorganization meeting were then presented and after an opportunity for corrections, it was moved by Director Pearson, seconded by Director Thiessen and carried that these minutes be approved as presented.

5. Marketing and Asset Management

A. PIRA Commodity Fundamental Price Outlook

Ken Rutter, Vice President-Marketing and Asset Management, introduced Allan Stewart, PIRA Executive Director-Electric, who spoke about PIRA's outlook for commodity prices.

6. General Manager's Report

General Manager Sukut reported on the January 2015 Manager's Advisory Committee (**MAC**) meeting. The main topics of discussion were joining Southwest Power Pool (**SPP**) and the potential buy-out of the Rural Utilities Service (**RUS**). Mr. Sukut conducted 10 employee sessions last week.

7. Western Fuels Association Update

General Manager Sukut noted that there is a meeting scheduled to discuss the organization of Western Fuels Association (**WFA**) on February 26, 2015. The group will discuss the future of WFA and what type of background the new CEO should have. He noted that currently, the group is leaning toward hiring someone familiar with shipping coal via rail rather than a mining engineer.

8. Office of General Counsel Report

Mr. Olson reviewed current litigation and matters of interest to the Cooperative. He noted that the majority of his report would be presented during executive session.

9. Transmission Report

Mike Risan, Senior Vice President, Transmission, provided an update of the various activities associated with the integration into SPP. Staff continues to assist the members to determine which member facilities could be included in SPP. He noted that Basin Electric might want to consider, where it makes sense, to offer to purchase certain of the members' facilities for inclusion into SPP. A fair and consistent method to determine which member facilities to purchase and which not to purchase must be established. He hopes to have a recommendation for the board after the next MAC meeting.

Mr. Risan also discussed seams and settlement issues associated with the areas where the cooperatives have an Interconnection & Common Use Agreement (**ICCUA**) with Montana-Dakota Utilities Co. (**MDU**) and where Central Power presently has an Integrated Transmission Agreement (**ITA**) with Otter Tail Power Company (**OTP**). The ITA agreement terminates at the end of 2015.

Basin Electric will join SPP on October 1, 2015. At that time, Corn Belt Power Cooperative (**Corn Belt**) plans to join SPP as a full transmission-owning member. Northwest Iowa Power Cooperative (**NIPCO**) would also like to join SPP as a full transmission-owner member. Any existing facilities Basin Electric leases from a member would be rolled in to SPP. On January 1, 2016, East River plans to join SPP as a transmission-owning member. Central Power is interested in placing its qualifying facilities in SPP as well but likely via a lease through Basin Electric.

The NITSA application, which specifies Basin Electric's load, generation and delivery point details has been submitted to SPP.

The NITSA application was submitted based upon the assumption that only the existing Integrated System (**IS**) would be moved into SPP. The document will have to be updated as more member facilities are transferred to SPP.

Work continues on annual transmission revenue requirement calculations and testimony to be filed with the Federal Energy Regulatory Commission (**FERC**) on April 1, 2015 to move our transmission facilities into SPP. The assumed rate of return in this filing will be 11.02% based on the average of rate of return for SPP members plus a 50-basis-point adder for joining an RTO.

The next milestone is a March 18-19, 2015, meeting hosted by SPP in Denver of the Western Area Power Administration (**WAPA** or **Western**), Basin Electric and all other parties bringing transmission facilities into the UMZ rate zone of SPP.

Staff has discussed Basin Electric's official status with SPP. Once the $6,000 annual membership assessment is made, Basin Electric becomes an SPP member. In response to a request by SPP, we submitted a list of the committees upon which we'd like to have representation and a list of candidates. On February 6, we received our first invitation to participate in a committee; Valerie Weigel, Manager, Marketing Financial Analytics, will serve on the Market Work Group.

Mr. Risan noted that the winter peak in the Williston Basin load pocket was approximately 200 MW over last year's peak.

Compliance staff continues to work on the FAC-008 facility rating mitigation plan for the MRO region. Staff continues to prepare for the WECC audit in September and to comply with the North American Electric Reliability Corporation (**NERC**) Critical Infrastructure Protection (**CIP**) Standards which begin April 1, 2016.

A. Mingusville Switching Station

Mr. Risan reported that the Mingusville Switching Station would be a three-breaker 230 kV ring bus on the WAPA Medora-to-Dawson County 230 kV transmission line. This is a new switching station to serve pumping loads in the Williston Basin. It will be the interconnection point for Golden West's 230/115/57 kV Beaver Hill Substation and will be owned by Western. Basin Electric is responsible for the cost, estimated to be $5,950,000, which will be recovered through the SPP Tariff. Western requires advance funding of the project. We continue to work on outstanding details as Western has not agreed that the substation is eligible for inclusion in SPP at this time. In order to provide clarity to our member, he recommended the project be approved subject to negotiation of an acceptable final contract with Western.

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

R01.02-10-15 RESOLVED, that the CEO and General Manager, or his designee, is authorized to execute agreements with and provide advance funding to the Western Area Power Administration for the construction of the Mingusville Switching Station, contingent upon the negotiation of an acceptable final contract.

B. Revised Interconnection & Common Use Agreement

Mr. Risan reported that the original ICCUA with MDU was signed in 1972 and provided for facility sharing based on investments and loads. Due to load growth in the Williston Basin, negotiations regarding payments under the ICCUA continue.

He noted that Sheridan Electric built a line parallel to the Williston-to-Grenora 115 kV line which Basin Electric proposed be put into the ICCUA. MDU initially objected and said MDU didn't need the line. The parties have since reached a temporary compromise position until such time as the line is put into SPP and MDU will take SPP service.

He then presented Supplement No. 23 to the MDU ICCUA which reflects the compromise position of the parties. This supplement would only affect Upper Missouri members. The negotiated Supplement would be retroactive to January 1, 2015.

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

R02.02-10-15 RESOLVED, that the CEO and General Manager, or his designee, is authorized to execute the revised Interconnection and Common Use Agreement Supplements and Agreements, including Termination of Supplement #23.

10. Cooperative Planning Update

Dave Raatz, Vice President of Cooperative Planning, reported that if you look at the January member billing peak compared to estimated peak, there were a number of members, based on the 2014 load forecast that came in quite a bit higher than the budget and also members that came in below budget. From a budget perspective, across the Basin Electric membership, loads were 58 MW higher than budget. This sounds misleading. To really understand the load growth, you have to go back a couple years. There were a lot of weather-related issues. From January 2013 to January 2014, the Cooperative experienced over 500 MW of load growth. During that time, there was a great deal of harsh weather and tremendous amounts of grain drying that lasted into December/January. We reached several member high billing peaks in 2013 and in January 2014.

When comparing January 2014 to January 2015 (31 MW across Whole Membership), only Upper Missouri had significant growth (213 MW). Most of the other members' loads were the same or less than the previous year. He noted there were also issues with freezing at the new distributed generation facilities last year. Upper Missouri is not as impacted by mild weather as a member with more residential growth.

SPP has requested substantial amounts of additional information since our initial submittal of the NITSA Application and Market Participant registration from several months back. Our most recent submittal of both on January 30. Basin Electric registered generation price points within the SPP footprint compared to SPPs total of more than 600. Basin Electric also registered 4 settlement areas for load that represent about 800 meters that Basin Electric and WAPA will use to determine what those loads are.

Today we have obligations to NIPCO at four delivery points off the IS. When NIPCO puts its system in the SPP, Basin Electric will have 100 delivery points to NIPCO off the SPP system.

The new transmission service policy goes into effect January 1, 2016. When these members join SPP on October 1, 2015, all of their costs will roll-up into the Upper Midwest billing zone and Basin Electric will pick up all of the costs of their transmission systems. SPP will provide Basin Electric with an invoice and Basin Electric will need to determine what portion of that cost should be passed back to NIPCO and Corn Belt for Basin Electric's share of the investment. He noted that this is a work in progress.

Three members have stated they want to be transmission owners of SPP, which gives them the right of representation on various committees. Basin Electric has staff that monitors what's going on in RTOs. The members will have to do some of that monitoring as well and there has been discussion on whether we can share some of those monitoring costs. Basin Electric is also encouraging its other members to join SPP. Mr. Raatz noted that he and Mr. Risan have said that to the extent that a member wants to join SPP as a transmission-owning member, Basin Electric will pay the $6,000 per year SPP membership fee. If a member doesn't join as a transmission-owning member, Basin Electric would lease their facilities and there would be many lease accounting complications. Ms. Deisz has also recommended that Basin Electric pay the members' SPP annual membership fees in order to not have to deal with lease accounting.

Once facilities are put into SPP, SPP will have the RTO right to utilize these facilities to provide transmission service to other entities. The SPP member has no say in which entities it will or will not serve.

MDU Settlement Impact. Eight member systems would be impacted by a settlement with MDU. The OTP settlement would impact a much smaller subset of Basin Electric's members. The outcome will have a significant impact on power supply decisions.

Under both of these settlement arrangements, if a member ends up paying a FERC pro forma wheeling charge, Basin Electric would pick up the FERC pro forma wheeling charge associated with the Basin Electric power supply delivery. To the extent that some of these old, one-wheel discounted transmission rates go away, the member will be responsible for the pro forma rate going across the WAPA portion and some may have to pay a pancaked (two open access fees) wheeling charge.

A meeting to determine the value, from each entity's (Tri-State, NPPD and SPP) perspective, of maintaining the existing wheeling arrangement has been scheduled for March 9. Other members, such as the District 9 members, don't want to do anything October 1, 2015 and want to wait to see what happens after January 1, 2016. There is nothing that prohibits the members from waiting to make a decision.

Remaining registration activities include updating the SPP NITS agreement (delivery points with NIPCO and Corn Belt) (March), document SPP transmission service arrangements (February), document pseudo-tie arrangements (February), execute SPP operating agreement (March) and submitting the SPP filing to FERC in April. Once all this is done in the federal arena and everyone sees all the transmission, then it's potentially subject to objections from others. WAPA has already stated it will file an objection to lines less than 60 kV.

Contract Issues. As we look at what we think we need for contract modifications. We probably have three documents to modify: the wholesale power contracts, a Power Services Agreement and the WAPA scheduling agreement. The wholesale power contracts are being extended through 2075 because of the 60-year life for the coal facilities and the 50-year life on the gas facilities. The Management Advisory Committee thought this was a reasonable request. He then reviewed contracts affected by the discontinuation of resource adders.

Under the federal service exemption, WAPA has a hard-wired four percent loss with SPP per the SPP Tariff. The WAPA contracted delivery points to its customers go to the edge of the old IS. As we have members that add more facilities to the UMZ rate zone, there are three percent losses on the Corn Belt system (for example). As we look at how much of the Corn Belt system would be included inside SPP, we are probably looking at 2.25% losses. By adding in a member system, it will increase the losses of the UMZ. We don't know the magnitude, but we do know Basin Electric's new delivery point and so we'll get reduced delivery of sales to the members. Where the issue is, as we understand the SPP process is what happens to the extent there's an under collection of losses. If we look at losses Basin Electric has and WAPA has and whatever the difference is, is allocated to the non-federal transmission service load. Basin Electric would potentially be picking up the losses for Basin Electric and WAPA. This could require a modification to Rate Schedule A. If the Basin Electric and WAPA delivery points are not at the same point, Basin Electric could supply the losses associated with the federal power deliveries at Basin Electric's Class A Member Rate. While we have discussed this with the MAC, it needs more discussion with the members.

The second topic we have discussed is the socialization of member transmission returns on investment. This is not typically considered a cooperative cost. Is it appropriate to socialize those costs within the Basin Electric family? Staff is preparing a white paper to quantify the dollars.

11. <u>Recess and Reconvention</u>

At 11:45 a.m., President Peltier recessed the meeting until 12:30 p.m., at which time the meeting reconvened with President Peltier continuing to preside and Secretary Gary C. Drost continuing to keep the minutes.

12. <u>Roll Call</u>

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

Don 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 and General Manager Paul M. Sukut and Assistant Secretary Claire M. Olson and staff members Jamey Backus, Robert J. Bartosh, Eric Carufel, Tammy DeWitt, Mike Eggl, Mark D. Foss, Robert Frank, Matt Greek, Dan Hagel, John Jacobs, Becky Kern, Janet Kubisiak, Rod Kuhn, Deborah Levchak, Sharon Lipetzky, Jim Lund, Jay Lundstrom, Gavin McCollam, Dave Raatz, Mike Risan, Ken Rutter, Susan Sorensen, Steve Tomac, Kevin Tschosik, Valerie Weigel, Michelle Wiedrich and Lyle Witham.

Also present were East River director Ken Gillaspie, Mor-Gran-Sou Director Casey Wells, DGC director Alan Klein and DGC Vice President and Chief Operating Officer David J. Sauer.

13. Executive Session

At 12:30 p.m., the Board recessed into executive session for Mr. Sukut's performance evaluation. At 1:30 p.m., the Board arose from executive session.

14. Cooperative Planning Update, continued

A. 2015 Load Forecast Update

Jay Lundstrom, Lead Load Forecast Analyst, noted that the 2014 Load Forecast was completed nine months ago. The update reflects a two-year delay in the Keystone XL Pipeline, additional power sales due to the GRE-fixing members and the updated Energy Sector Analysis. He reviewed Williston Basin oil production projections and the weather normalized forecast for each of Basin Electric's districts. Our loads continue to grow at twice the national average.

He then reviewed the 2015 Load Forecast Update and the 2015 Alternative Case (a 50% drop in drilling activity in the Williston Basin and no Keystone XL Pipeline). Mr. Lundstrom then recommended that the 2015 Load Forecast Update be approved.

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

R03.02-10-15 WHEREAS, Basin Electric Power Cooperative and its member systems have completed a detailed econometric forecast for the period of 2014 through 2035;

WHEREAS, the forecast was prepared in accordance with current Rural Utilities Service regulations using reasonable methodologies and assumptions;

NOW THEREFORE, BE IT RESOLVED, that the Board of Directors of Basin Electric does hereby adopt and approve the 2015 Load Forecast Update as a reasonable forecast of Basin Electric's future deliveries to its member systems.

B. NextEra Line Purchase Update

Mr. Raatz reported that the NextEra project needs a 35-mile 230 kV transmission line from its wind project to a new substation between the existing Belfield and Rhame Substations and the Belfield-to-Rhame transmission line. Basin Electric staff decided to turn the construction of this line over to NextEra to eliminate the risk that the line and substation would not be complete by year-end and NextEra would lose production tax credits (**PTC**). Upon completion, the substation and potentially the line will be turned over to Basin Electric.

In order for the substation to be available for additional deliveries, Basin Electric will be responsible for add-ons and cost overruns.

During discussions with NextEra, we learned that Roughrider Electric needs a 115 kV line into this same general area. Under SPP rules, if there are two different customers at the end of the line (in this case, NextEra and Roughrider), this line would be includable in SPP.

Basin Electric would like to buy this line as we would be better able to manage and perform operations and maintenance on the line. He reviewed the economics of this transaction (PPA savings, increased annual cost, increased RTO ROI cost recovery and the Basin Electric increased UMZ cost), resulting in an estimated annual savings of $900,000. If NextEra retained ownership of the line and put it under the tariff, Basin Electric would see higher annual costs from SPP of approximately $1 million. Thus, there is a net benefit to Basin Electric of owning the line of approximately $1.9 million per year.

Mr. Greek reviewed the required agreements (Basin Electric Interconnection Agreement, Transmission Line Purchase Sale Agreement, Revised Power Purchase Agreement and EPC or similar agreement with NextEra relative to NextEra-supplied facilities). He expressed concerns and they responded and produced documents reflective of the technical work on the substation portion.

NextEra has not yet obtained a Large Generator Interconnect Agreement for this project, which generally defines the standards observed on and attributes of the project. Basin Electric staff desires that the substation and transmission line be built to Basin Electric standards. Work to date includes detail engineering and procurement that may not be to Basin Electric's standard; equipment ratings do not reflect longer-term expansion needs; Roughrider's needs have not been considered; and operability and maintainability may not be optimal. NextEra is generally agreeable to this. Added cost is an issue, as is a delay in the scheduled completion.

Staff continues to work with NextEra through technical comments. At Basin Electric's suggestion, NextEra retained Ulteig for engineering work. Work will need to be covered by an engineer, procure and construct (EPC) contract or similar contract. Construction may likely need to be stopped on the NextEra-supplied substation and transmission line to develop appropriate design basis, negotiate terms and execute the EPC. Due to extension of the PTC deadline, there is now no rush, from a Basin Electric perspective, to complete this project by December 31, 2015. We are committed to minimizing potential rework of acquired assets while ensuring assets are developed with an appropriate long-term view.

15. Communications and Administration Report

A. Bakken Update from Lynn Helms

Mike Eggl, Senior Vice President, Communications and Administration, introduced Lynn Helms, Director of Mineral Resources Department for the state of North Dakota. Mr. Helms presented his views on oil production in the Bakken given the substantial drop in oil prices. He noted that 90% of the Bakken's wells are in production mode. The rig count today is 137, the lowest since July of 2010. Daily production has reached 1.2 million barrels per day. The active well count reached a new record at 12,125. Three thousand permits were issued in 2014. He noted that oil today is at $44 per barrel and that no wells would be shut-in until the price of oil drops to close to $15 per barrel. In terms of geographic area, the Williston Basin is the largest oil field in the world. Saudi Arabia has more reserves, but the Williston Basin covers more area.

16. Financial Services Report

A. IHS-CERA Energy Commodity Price Outlook

Andrew Buntrock, Manager of Financial Planning and Forecasting, introduced Jim Burkhard, Vice President of Oil Markets and Energy Scenarios for IHS-CERA, who made a presentation on IHS-CERA's forecast of energy commodity prices.

17. Cooperative Planning Update, continued

A. Resource Development

Becky Kern, Director of Utility Planning, presented graphs of the projected summer Basin Electric Supplemental Demand for the baseline and alternative cases and noted that Power Supply plans must be developed to meet both cases. She suggested shorter-term purchases to meet the difference between the baseline and alternative cases and to maintain a three to five-year resource development option.

Ms. Kern then discussed load shifts, reduced load, the MISO, SPP and West areas and the options for purchases and participation in projects. Staff is currently evaluating the timing of an SPP combined-cycle unit and availability of market purchase opportunities. She then reviewed the mid-term and long-term resource needs and the decision timelines for these decisions.

B. Strategic Planning

Shanda Traiser, Director of Strategic Planning, noted when the directors first began the strategic planning process, they participated in a survey to determine where Basin Electric was in terms of strategic planning at that time. She distributed the new survey, which looks at the results of six different areas and asks how important you think those areas are and how you rate the Cooperative's progress. She will present the results at the March board meeting.

18. Recess and Reconvention

At 4:45 p.m., the meeting recessed until 7:30 a.m. on February 11, 2015, at which time the meeting reconvened, President Peltier continuing to preside and Secretary-Treasurer Gary C. Drost keeping the minutes thereof.

19. Roll Call

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

Don 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 and General Manager Paul M. Sukut and Assistant Secretary Claire M. Olson and staff members Jamey Backus, Tracie Bettenhausen, Andrew Buntrock, Eric Carufel, John Ciz, Tammy DeWitt, Mike Eggl, Pius Fischer, Mark D. Foss, Matt Greek, Dan Hagel, Ellen Holt, John Jacobs, Steve Johnson, Becky Kern, Janet Kubisiak, Rod Kuhn, Anine

Lambert, Deborah Levchak, Jim Lund, Deb Olafson, Curt Pearson, Dave Raatz, Mike Risan, Josh Rossow, Ken Rutter, Susan Sorensen, Kelly Suko, Kevin Tschosik, Shelly Wanek, Amanda Wangler, Valerie Weigel, Michelle Wiedrich and Lyle Witham. Also present was East River director Ken Gillaspie.

20. Executive Session

At 7:30 a.m., the Board retired into executive session to hear reports on possible new members of the Cooperative, LRS-BART and the *Basin Electric/Western Fuels Association v. BNSF* case. At 9:40 a.m., the Board arose from executive session.

21. Operations Report

John Jacobs, Vice President of Operations, reviewed the Cooperative's safety performance for the month and provided bus-bar costs for the coal-fired fleet. He reviewed the equivalent forced-outage rate trends for a 24-month period on the generation of the solid fuel units. He noted that the contract with Union Local #612 expires at the end of February and that negotiations are underway. On January 31, the Laramie River Station (**LRS**) coal stockpile contained sufficient coal for 29 days burn for all units at full load.

He reported that January fleet generation came in 2.7% above budget. Individual availability and capacity factors for the coal-based generation stations were as follows:

Unit	Availability	Capacity Factor	Unit Rating	Comments
AVS #1	100%	94.4%	450 MW	Scheduled surveillance test of facility; fuse blew in scrubber control system
AVS #2	100%	93.5%	450 MW	Surveillance test of facility; blown fuse in scrubber control system
DFS	100%	102.77%	386 MW	Scheduled surveillance test
LRS #1	100%	89.85%	570 MW	Market-driven issues.
LRS #2	100%	96.52%	570 MW	Market-driven issues.
LRS #3	92%	92.15%	570 MW	Economizer tube leak; flow transmitter operator error
LOS #1	100%	88.87%	221 MW	
LOS #2	100%	90.90%	448 MW	

A. Distributed Generation Update

Kevin Tschosik, Distributed Generation Manager, reported on distributed generation and noted that there were no recordable safety incidents in January.

The January generation at the distributed facilities were as follows:

Unit	**Monthly Availability (%)**	**Monthly Generation (MW)**	**Unit Rating (MW)**	**Comments**
Groton Unit #1	94.82%	551 MW	100 MW	Ran for load demand. Failed fire detector.
Groton Unit #2	94.03%	86 MW	100 MW	

Culbertson CT	98.89%	4,741 MW	100 MW	Ran for load demand. Outage to load software for SPP; repair expansion joint.
WY Dist. Gen.	98.98%	68 MW	54 MW	
SMS Unit #1	100%	Did not run	60 MW	
SMS Unit #2	99.50%	Did not run	60 MW	
Deer Creek	88.02%	62,199 MW	300 MW	
PGS Unit #1	94.18%	6,256 MW	45 MW	Ran for load demand. Outage to load AGC software for SPP; Unit #1 clutch cooler failed.
PGS Unit #2	94.38%	3,761 MW	45 MW	
PGS Unit #3	95.03%	6,595 MW	45 MW	
LCS Unit #1	96.51%	8,478 MW	45 MW	Outage to load software for AGC control for SPP.
LCS Unit #2	97.72%	13,353 MW	45 MW	
LCS Unit #3	98.34%	17,785 MW	45 MW	

During January, the Pioneer Generating Station (**PGS**) ran in synchronous condensing mode 377.4 hours and the Lonesome Creek Station (**LCS**) for 2.03 hours. The Wyoming Distributed Generation had 17 west-side spinning reserve calls for the month. Spirit Mound Station did not run in January.

PrairieWinds ND 1. Control system software and hardware upgrades were completed. The one outage during the month was due to icing, lasted 23 hours and 23 minutes and resulted in the loss of 1,624 MW hours.

PrairieWinds SD 1. The control system software/hardware upgrade is planned to be completed in the March-April time frame.

The east-side peak occurred on January 8, 2015 at 1900 hours. At that time, wind generation was as follows:

Wind Project	**Load Factor during the Peak (MW)**	**Capacity Factor (%)**		**Project Total**
		Month	**YTD**	
Baldwin	93 MW	51%	51%	99 MW
Day County	87 MW	53%	53%	99 MW
Edgeley	34 MW	45%	45%	40 MW
Highmore	24 MW	40%	40%	40 MW
Iowa Wind	38 MW	45%	45%	45.1 MW
Other Projects (Chamberlain & Pipestone)	1 MW	10%	10%	3.4 MW
PrairieWinds ND	114 MW	54%	54%	123 MW
PrairieWinds SD	168 MW	59%	59%	162 MW
Wilton	81 MW	44%	44%	99 MW
Total Monthly Wind Generation	641 MW	n/a	n/a	712 MW
Average Capacity Factor	n/a	51%	51%	n/a

B. Leland Olds Station Update

Jamey Backus, Leland Olds Station (**LOS**) Plant Manager, reported that on November 3, 2014, the LOS employees reached 2.5 million man-hours without a Days Away, Restricted or Transferred (**DART**) incident. In 2014, LOS achieved 101.2% of its budgeted generation. Unit #1 reached 98.6% of its budgeted generation, had availability of 73.1% and an 81.6% running plant capacity factor (**RPCF**). Unit #2 generated 102.3% of its budgeted generation, had an availability of 90.1% and a RPCF of 79.2%.

Year-to-date 2015, LOS generated 111.8% of its budgeted generation.

He then discussed and presented photographs of activities undertaken during the major outages at both units.

The Unit #2 outage is scheduled for April 5 to May 31 and will include the repair of all 12 cyclone burner fronts, installation of new hydrogen seals, internal alignment and inspection, as well as installing flow distribution plates in the air heater, perforated plates in the precipitator and installation of the Selective Non-Catalytic Reduction (**SNCR**) and mercury control ports in the boiler.

The LOS coal stockpile stands at approximately 650,000 tons.

Mr. Backus reported that ME2C technology was chosen for mercury removal based on efficiency and long-term costs. Staff is currently working with the contractor on an installation schedule.

SEGA is out for bids on the equipment for the SNCR project to reduce NO_x and is finalizing the building specifications for construction bids. Groundbreaking is expected in June of this year.

C. Lining of LRS Circulating Water Piping

Dan Hagel, Mechanical Engineer at LRS, reported that circulating water pipes #CW1 and #CW2 on Units #2 and #3 were lined during the 2013 and 2014 maintenance outages, respectively. The specification for the original lining work did not include lining the ends of the pipe runs to above ground or above concrete. He presented photographs showing the areas requiring lining. The work on lining this additional piping adds up to 9,900 square feet of pipe surface area per unit. To date, expenditures on this additional work include $246,500 for Unit #2 and $297,200 for Unit #3.

Westcon has submitted a change order request for $238,200 for the additional work on the Unit #1 circulating water piping. According to the terms of the contract, there will be time and materials charges of approximately $50,000 depending on the "as-found condition" of these four areas of pipe.

Unexpected repairs included patching 30-plus holes in the Unit #2 and 50-plus holes in the Unit #3 circulating water piping in 2013 and 2014. These repair costs plus the cost of coating the extra 9,900 square feet of circulating water piping in both units used up all of the contingency dollars included in the budget for this project.

He presented Amendment #2 to the CPR for $600,000, which has been approved by the MBPP Engineering & Operating Committee and the MBPP Management Committee and recommended that it be approved.

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

R04.02-10-15 RESOLVED, that Amendment #2 to Capital Project #200120 (Work Order 13048) be amended to increase the amount of the contract by $600,000 for work outside the scope of the initial contract to a total cost of $24,553,000; and

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

22. Marketing & Asset Management Report, continued

A. Purchased Power & Non-Member Sales Report

Valerie Weigel, Manager, Marketing Financial Analytics, reported that power and gas prices continued to fall in January. Estimates show January member loads were about three percent lower than the forecast. Base load generation came in higher than budget, while member loads came in less than planned, creating a decrease in natural gas runs and an increase in non-member sales over the budget. Basin Electric hedges continue to be positive versus the budget, but out-of-the-money versus the market. The 2015 Basin Electric natural gas/purchase power hedge plan is approximately 95% complete so we were able to take advantage of lower prices in January. Software implementations, training and testing are in full swing for joining SPP.

She reviewed the 2016 natural gas forward price history, January average real-time prices, January 2015 member loads (load forecast versus estimated actuals versus January actuals) on east and west sides, as well as a summary of January energy deviations. She reviewed the Execution of 2015 Basin Electric Natural Gas/PP Hedge Plan.

Marketing participated in the February MISO auction for financial transmission rights.

Ms. Weigel reported on software, strategies, staffing, plant coordination and the timeline associated with joining SPP.

B. Basin Electric Hedge Plan

Ms. Weigel reported that the goal of a hedge plan is to protect against erosion of revenue or an increase in expenses. She noted that in order to create a hedge plan, staff must review financial forecast volumes and prices for Basin Electric and DGC; determine the potential volatility within those forecasted volumes and prices; determine how much revenue and expense the Cooperative is willing to expose to the volatility in the market; establish the outlook on forward prices; and then create specific hedge plans with tactics that accomplish our goals.

C. Approval of WBI Interconnect Agreement

Ms. Weigel reported that the PGS is located on the Williston Basin Energy (**WBI**) Stateline pipeline. The plant is located within close proximity to a new natural gas processing plant. To date, no compression is required on the Stateline pipeline to serve PGS. The existing transport agreement with WBI was executed in 2012. This is an agreement for interruptible transportation. An analysis on firm transport versus interruptible transport with back-up fuel was performed. Interruptible with back-up fuel provides significant savings. She noted that compression and associated fuel charges will be applicable only if WBI is required to construct additional compression to serve PGS. Basin Electric is not subject to construction costs for compression to serve other facilities. She then reviewed the contract details and recommended that the Amendment be approved.

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

R05.02-10-15 RESOLVED, that the CEO and General Manager, or his designee, is hereby authorized to execute the amendment to the WBI/Pioneer Station Phase 3 Interconnect Agreement as presented.

23. Engineering & Construction Report

A. Funding Chart

Matt Greek, Senior Vice President-Engineering and Construction, reported that contracts totaling $35.1 million would be presented for approval this month. He then presented the listing of major projects including the approved budget amounts, total amounts committed and completion dates.

B. AVS/LRS Mercury Control Projects Update

Mr. Greek reported on the projects to bring mercury emissions at LRS and the Antelope Valley Station (**AVS**) into compliance with the Environmental Protection Agency's (**EPA**) Mercury and Air Toxics Standards (**MATS**) rule. EPA has granted both sites an extension to June 1, 2015. Mr. Greek noted that the planned modifications to the silo design include abrasion and explosion panels. The LRS Unit #3 silo is currently on the assembly line. The AVS Unit #1 silo component fabrication is in process. He noted that the budget is very tight and that silo fabrication delays may affect delivery dates.

C. 345 kV Projects Update

Mr. Greek provided the construction update. There were no OSHA recordable incidents or DARTs in January. Construction of the Judson Substation and the AVS to Judson portion of the transmission line are behind schedule.

D. Emmons County Land Options

Kelly Suko, Property and Right-of-Way Project Coordinator, reported that staff is still in the process of obtaining options in Emmons County, North Dakota, west of Linton for a combined-cycle unit. The preferred site is on higher ground in Section 21 along the highway.

E. LRS SCR Phase IIA Update

Jim Lund, Senior Project Manager, reported that this project began in January of 2014 when the EPA issued its regional haze plan requiring NO_X reduction at all three LRS units by March 2019. A Front-End Engineering and Design (FEED) study was done to develop the scope and preliminary budget for the project by the end of 2014. Phase 1 was completed last month. Sargent & Lundy was hired as a consultant. To date, approximately one-third of the Preliminary Survey & Investigation (PS&I) budget has been committed to this effort.

SCR Phase 1 results identified anhydrous ammonia as the reagent and the need for sulfur trioxide (**SO_3**) mitigation, new ID fans and an updated plant electric system. The conceptual ductwork and structural steel arrangement, the preferred construction plan and the maintenance facility relocation plan were also identified. Mr. Lund then presented images of the plant site showing the proposed location for the ammonia storage and receiving, boiler buildings, SCR reactor boxes and the two cranes and crane swings to install the reactor boxes.

He then reviewed the cost estimates for each unit which were based on material and labor from Sargent & Lundy, along with projected escalation and contingency costs. Basin Electric costs for engineering facility impact alleviation (the new maintenance center), taxes and interest during construction were added. There is also a budget for community impact as this project would be expected to bring 350 to 400 people to the community over a two to three-year time frame. If the project were to begin today, the cost estimate would be $755,953,879.

Another purpose of a FEED study is to identify issues you were not aware of which require further definition such as (in this case) regional haze outcome, condition of flue gas structures, material quantities and direct pricing, labor availability and rates and the potential socio-economic impact on Platte County.

He recommended that Sargent & Lundy be retained to perform this additional engineering work to further define the project and budget. The estimated cost for this engineering work is $2 million. The estimated total cost for all of the Phase IA work is $7 million, but $2 million remains under the original Phase 1 budget. The MBPP Management Committee approved $5 million for SCR activities at its January meeting.

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

<u>**R06.02-10-15**</u> RESOLVED, that the SCR Phase IIA scope and budget of $4.0 million is hereby approved; and

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

Mr. Lund presented a resolution to extend Sargent & Lundy's contract to include the SCR Phase 1A work.

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

<u>**R07.02-10-15**</u> RESOLVED, that the Phase IIA engineering scope project be awarded to Sargent & Lundy at a not-to-exceed cost of $2 million; and

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

F. <u>PGS Phase III Construction Management</u>

Josh Rossow, Project Manager, reported that civil and site design for Phase III of PGS is 80% complete, mechanical design is 50% complete, structural design is

50% complete, electrical design is 30% complete and engineering progress depends on timely equipment drawings.

Wartsila submitted its detailed design package last month. Final designs will be submitted later this month. The engines are on schedule to be delivered in November. Wartsila is currently working on shipping logistics.

He reported that procurement is 20% complete, 11 of the 36 total contracts are either out for bid or are in review. Three contracts have been awarded. He reviewed the upcoming board actions that will be requested. The hearing before the North Dakota Public Service Commission is scheduled for March 2, 2015 in Williston, North Dakota. The air permit should go out for the 30-day public comment period yet this month. The conditional use permit application will be submitted to Williams County later this month.

Construction is scheduled to begin on May 1. The target early construction completion date is June 1, 2016 and the late target completion date is October 1, 2016. The construction schedule currently contains 21 days of float; however, much of that float would be used up if weather delays the start of construction.

He then reviewed the fuel supply terms for PGS Phase I and III. The $1.2 million aid to construction was not budgeted, but should be covered by the contingency. Detailed engineering has been turned over to Burns & McDonnell, which has worked on nine of the last 12 reciprocating engine plants in the U.S.

He recommended that Burns & McDonnell be retained to provide construction management for the project.

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

R08.02-10-15 RESOLVED, that the contract for Construction Management Services for the Pioneer Generation Station Phase III project be awarded to Burns & McDonnell in an amount not to exceed $6,800,000; and

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

24. Recess and Reconvention

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

25. Roll Call

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

Don 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 and General Manager Paul M. Sukut and Assistant Secretary Claire M. Olson and staff members Tracie Bettenhausen, Andrea Blowers, Dean Bray, Eric Carufel, Ted Cash, John Ciz, Greg DeSaye, Tammy DeWitt, Mike Eggl, Mark D. Foss, Matt Greek, Jen Holen, Ellen Holt, John Jacobs, Steve Johnson, Becky Kern, Rod Kuhn, Deborah Levchak, Sally Meier, Faye Miller, Mary Miller, Dale Niezwaag, Deb Olafson, Josh Rossow, Ken Rutter, Jean Schaffer, Susan Sorensen, Steve Tomac, Shelly Wanek, Michelle Wiedrich, Lyle Witham and Roxanne Woeste. Also present was East River director Ken Gillaspie.

26. Engineering & Construction Report, continued

A. PGS Weatherization

Mr. Greek noted that there had been freezing problems at PGS and LCS last winter. He recommended approval of a budget to provide permanent insulated, heated steel structures to enclose the above-ground water piping from the NO_x injection skid to the turbine package for all three PGS units. The project scope includes foundations, structural steel, insulated metal wall panels, heating and ventilation, electrical and controls. He presented drawings of the enclosures and noted that the amendment to the budget is due to insufficient contingency, scope increases, lack of available electrical contractors in northwestern North Dakota and lower productivity due to cold weather construction.

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

R09.02-10-15 RESOLVED, that the budget for the PGS winterization enclosures, as presented, be increased $257,596 to a new total of $1,167,963; and

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

B. Decommissioning Cost Estimates

Mr. Greek reported that this work was undertaken by Engineering & Construction staff as a result of board discussions and a request from the Accounting Division. This work refreshed previous studies on Basin Electric's coal-fired power plants and took a fresh look at the Great Plains Synfuels Plant (**Synfuels Plant**). Draft results have been received and the report is in the process of being finalized.

The Synfuels Plant numbers compare favorably to a similar 1989 study escalated to 2015 dollars. The estimated net project cost of decommissioning AVS is $40,875,000; Dry Fork Station (**DFS**) is $8,071,000; Synfuels Plant is $253,279,000; LRS is $89,517,000; and LOS is $37,408,000.

C. Emerging Technologies

Mr. Greek reported that Mr. Sukut had asked him to take the lead on the Cooperative's studies of emerging technologies. He reviewed the outcomes, activities, approach and questions to be considered by the team with respect to emerging technologies. The next steps are to commission the team, refine/add questions to be answered, integrate ongoing work in emerging technologies, come to a consensus with the team on the initial body of work (with outcomes and time frames for completing it) and begin the work and regular communication of it.

27. Communications & Administration Report, continued

Mike Eggl, Senior Vice President-Communications & Administration, reported that regional legislative action, planning for the building additions and continued support for the SPP integration were the main focuses of the Communications & Administration Department this month.

The Right of First Refusal (**ROFR**) legislation which would provide a framework for how new transmission is built and paid for in an RTO environment moved forward in North Dakota. More work will need to be done in Montana prior to the next legislative session.

Steve Tomac, Senior Legislative Representative, reported on issues of interest to the Cooperative before the South Dakota Legislature.

Dale Niezwaag, Senior Legislative Representative, reported on ROFR and funding for the Allam Cycle project.

The initial east-side building addition will be presented to the Board in March for further review. The group has continued meetings with the engineers and architects. Specifically, they have chosen a consultant to help develop a plan for the building interior that will maximize space and respond to changing employee interests and work needs.

IS&T is providing a great deal of support to the SPP integration process. Work is still on track to meet the "go live" date of October 1, 2015.

Staff is working to send out surveys to the employees and membership, as well as a regional perception survey in the communities where the Cooperative's facilities are located. The employees and membership will be surveyed this month and the survey results will be compared with the pre-strategic planning survey results.

Mr. Eggl reported on activities planned by the Cooperative and others to raise money for "Brave the Shave", most of which goes to St. Baldrick's Foundation. He presented a video advertisement for "Brave the Shave" created by staff members Jen Holen and Greg DeSaye. He noted that many other organizations have activities planned for "Brave the Shave".

Ted Cash, Manager of Media Support Services, reported that Mary McLaury was named interim Chief Operating Officer of Touchstone Energy.

Mr. Eggl then reported that, in response to the Board's interest in day care, Basin Electric is attempting to partner with the Missouri Valley Family YMCA (**YMCA**) to provide day care services for children of employees of Basin Electric and several other large employers in the Bismarck/Mandan area. Each company would guarantee payment for a certain number of children for a specific period of time. He noted that a huge number of day care slots are needed in the community. The YMCA is the largest day care provider in the Bismarck/Mandan area, in the state, as well as in the United States. He said it looks like the YMCA has found a location. He noted that there is also a big need for day care in Beulah, Hazen and Wheatland, but so far we do not have a combination of a day care provider, a facility or partners in these communities.

A. Quarterly IS&T Report

Mark Kinzler, VP of Information Services & Technology, reported on the 2014 IS&T Work Plan. 2014 accomplishments include Allegro west-side implementation, WebEx, WebEx Connect and InterCall, Citrix implementation, SharePoint - Inside Basin, Microsoft Office 2013, TSM microwave upgrade, six-digit employee numbers and Security Response System (SRS) call center software upgrade.

He noted that staff is taking a hard look at the cost of running software, analyzing enterprise software packages for overlaps and effectiveness, ensuring we have solid documentation for interfaces and customizations, Microsoft Office 365 and video conferences.

He reviewed hardware activities planned for 2015, Business Planning, storage upgrades, evaluating backups, LRS circuit upgrades, numerous software upgrades (versions and security patches) and a number of new software projects are pending review and approval.

Neal Stroh, Director of Information Security, reported on cybersecurity projects and initiatives, Info-Tech's security assessment and compliance assessments, NERC Critical Infrastructure Protection (**CIP**) and data security standards in the payment card industry. He noted that NERC's CIP is a federal compliance framework developed and enforced by NERC and mandated by FERC that is designed to place tighter security controls around critical infrastructure to prevent the collapse of the bulk electric system.

B. Approval of 2015 Affirmative Action Plan

Shelly Wanek, Compensation/EEO/Recruitment Supervisor, reported that Basin Electric's Affirmative Action Plan (**Plan**) is revised each year according to federal and state law changes and to update statistics. The Plan has goals for hiring females and minorities and for veterans and individuals with disabilities. She then reviewed the changes and goals of the Plan and recommended that the 2015 Plan be approved.

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

R10.02-10-15 **RESOLVED**, that Basin Electric Power Cooperative's 2015 Affirmative Action Plan is hereby approved.

28. Financial Services Report, continued

Steve Johnson, Senior Vice President and Chief Financial Officer, distributed schedules for activities during the National Rural Electric Cooperative Association (**NRECA**) annual meeting in Orlando February 22-25.

He reported that the Member Investment Program set a record during January and had a January-end balance of $215,509,408.45 compared to $165,218,029.75 at the end of December. There currently are 43 active participants in the Program.

He reviewed 2014 estimated consolidated year-end margins/deficits and noted that Deloitte & Touché will review its audit with the board in March.

Shawn Deisz reported that the January 2015 Statement of Operations reflected an estimated net margin of $15.9 million compared to the budgeted net margin of $10.7 million for a favorable variance of $5.2 million.

Fitch. Mr. Johnson noted that Basin Electric is on the rotation to have its ratings reviewed by Fitch by February 15. He noted that he had had discussions with Fitch and reviewed some of the material presented during the annual rating agency trip in October of last year. They also discussed Updated Load Forecast. Fitch is concerned about low oil prices potentially reducing loads in the Williston Basin, reduced commodity prices and its impact on Dakota Gasification Company. Fitch is of the general opinion that a planned three percent budgeted margin is too small for an organization the size and complexity of Basin Electric. Fitch confirmed both Basin Electric's long-term and short-term ratings with a stable outlook.

Economy. He reviewed current economic statistics.

RUS Buyout. Mr. Johnson noted that on February 20, staff will meet with representatives from Goldman Sachs, Sutherland, Asbill & Brennan and Orrick, Herrington & Sutcliffe (**Orrick**) to start due diligence work. The week after that, Orrick will be here to meet with senior managers to start gathering information that will be used in composing the offering memorandum. Staff will continue working on the proposed financing structure and plan to have a proposed structure for the financing by the end of February. Nondisclosure agreements will be executed with 10 to 20 investors.

Decommissioning Trust Review. Susan Sorensen, Vice President & Treasurer, reported that staff attended the Duane Arnold Energy Center (**DAEC**) annual nuclear decommissioning trust review. She noted that on September 1, 2009, Basin Electric and Corn Belt entered into a power purchase agreement and Corn Belt became a Class A member of Basin Electric. The obligation for the nuclear facility decommissioning fund is addressed in the Power Purchase Agreement. The decommissioning has two pieces: (1) the external Nuclear Regulatory Commission (**NRC**); and (2) internal (spent fuel management and return to green field site). Corn Belt is responsible for 10% of the decommissioning costs when the DAEC NRC license expires in 2034. Corn Belt met the full funding requirement on April 30, 2011, at which point, as set forth in the Power Purchase Agreement, Basin Electric assumed all future funding liability.

Morgan Stanley did a 2014 year-end recap. The fund is performing very well and there are no requirements for additional funding at this time.

29. Date and Place of Next Board Meeting

The next regularly scheduled meeting of the Board of Directors will take place March 10-12, 2015, at Basin Electric's headquarters building in Bismarck, North Dakota.

30. Executive Session

At 3:40 p.m., it was moved by Director Drost, seconded by Director Applegate and carried to retire into executive session for a report on pulsed electron beam technology for NO_x removal. At 4:00 p.m., it was moved by Director Brekel, seconded by Director Drost and carried that the Board arise from executive session.

31. Adjournment

At 4:00 p.m., it was moved by Director Drost, seconded by Director Gilbert and carried that the meeting be adjourned.

Gary C. Drost
Secretary-Treasurer