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November 26, 2014

RECEIVED
DEC 1 2014
PUBLIC SERVICE COMMISSION

Via Federal Express

Mr. Jeff Derouen
Executive Director
Public Service Commission
211 Sower Boulevard, P.O. Box 615
Frankfort, Kentucky 40602-0615

RE: ***BIG RIVERS ELECTRIC CORPORATION'S FILING OF WHOLESALE CONTRACTS PURSUANT TO KRS 278.180 AND 807 KAR 5:011 §13, CASE NO. 2014-00134***

Dear Mr. Derouen:

The Public Service Commission issued an order on November 21, 2014, in the above-referenced matter granting in part and denying in part Big Rivers Electric Corporation's petition for confidential treatment with respect to an ACES study. Ordering paragraph 6 of that order directed Big Rivers to file a revised version of the ACES study reflecting as redacted the portions of the study granted confidential treatment and reflecting as unredacted the portions of the study denied confidential treatment.

Big Rivers is seeking rehearing of the November 21 order. As such, Big Rivers cannot file a revised version of the ACES study with all of the portions of the study that were denied confidential treatment unredacted. However, Big Rivers is filing revised confidential and public versions of the ACES study consistent with its motion for rehearing.

Enclosed are (i) an original and ten (10) copies of a motion for rehearing; (ii) an original and ten (10) copies of a revised public version of the ACES study reflecting redactions consistent with the motion for rehearing; and (iii) one (1) sealed copy of a revised confidential version of the pages of the ACES study that contain confidential information, with the confidential information highlighted. Big Rivers requests that

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confidential treatment be afforded to the revised confidential version of the ACES study for the reasons explained in the motion for rehearing.

I certify that, on this date, a copy of this letter, a copy of the motion, and a copy of the revised public version of the ACES study were served on each of the persons on the attached service list by first-class mail. Also, on this date, a copy of the revised confidential version of the ACES study was served on each of the persons listed on the attached service list that have signed a confidentiality agreement by first-class mail.

Sincerely,

TAK

Tyson Kamuf
Counsel for Big Rivers Electric Corporation

TAK/lm
Enclosures

cc: Lindsay Barron, Big Rivers Electric Corporation
DeAnna Speed, Big Rivers Electric Corporation
Service List

Service List
PSC Case No. 2014-00134

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COMMONWEALTH OF KENTUCKY
BEFORE THE KENTUCKY PUBLIC SERVICE COMMISSION

RECEIVED
DEC 1 2014
PUBLIC SERVICE COMMISSION

In the Matter of:

SPECIAL CONTRACT FILING BY BIG RIVERS ELECTRIC CORPORATION PURSUANT TO 807 KAR 5:011§13	))))	CASE NO. 2014-00134

MOTION OF BIG RIVERS ELECTRIC CORPORATION FOR REHEARING AND RECONSIDERATION

Pursuant to KRS 278.400, Big Rivers Electric Corporation ("Big Rivers") hereby moves the Kentucky Public Service Commission (the "Commission") for rehearing of the Commission's November 21, 2014, order in the above-referenced matter. In support of this motion, Big Rivers states as follows:

The November 21 order granted in part and denied in part Big Rivers' request for confidential treatment of an ACES study, which Big Rivers filed as an attachment to its response to Item 3 of the Commission Staff's Initial Requests for Information. Big Rivers respectfully seeks rehearing to address portions of the order that Big Rivers believes are either unclear or inconsistent. More specifically:

1. In the November 21 order, the Commission granted confidential treatment to a forecasted margin amount contained in paragraph 3 on page 3 of the ACES study, but it did not grant confidential treatment to that same forecasted margin amount in paragraph 4 on page 3 of the study. Big Rivers requests the Commission grant rehearing of the November 21 order and grant confidential treatment to the forecasted margin amount in paragraph 4 on page 3 of the ACES study.

2. In the November 21 order, the Commission granted confidential treatment to the average LMP differential contained in paragraph 1 on page 9 of the ACES study, but it did not grant confidential treatment to that same amount in paragraph 4 on page 5 of the study. Big Rivers requests the Commission grant rehearing of the November 21 order and grant confidential treatment to the LMP differential amount in paragraph 4 on page 5 of the ACES study.

3. In the November 21 order, the Commission granted confidential treatment to the values in Figure 4 on page 7 of the ACES study, but it did not grant confidential treatment to the percent increase used to determine those values in Figure 4. That percent increase is set forth in paragraph 1 on page 7 and in the sentence between Figures 3 and 4 on page 7. If confidential treatment is not afforded to the percent increase, anyone can calculate the values in Figure 4 using the values in Figure 3. Thus, in order to give effect to the Commission's grant of confidential treatment for the values in Figure 4, Big Rivers requests that the Commission grant rehearing of the November 21 order and grant confidential treatment to the percent increase in the two locations it appears on page 7 of the ACES study.

4. In the November 21 order, the Commission granted confidential treatment to certain forecasted energy and demand rates contained in Figure 8 on page 9 of the ACES study. It is unclear whether the Commission intended to grant confidential treatment to the related percent increases in Figure 8. If confidential treatment is not afforded to the percent increases, the confidential energy and demand rates can readily be calculated. As such, Big Rivers requests the Commission grant rehearing of the

November 21 order and grant confidential treatment to the percent increases for the years 2021 and beyond contained in Figure 8 on page 9 of the ACES study.

5. In the November 21 order, the Commission granted confidential treatment to certain transmission costs in the last sentence in paragraph 1 on page 9 of the ACES study, but it is unclear whether the Commission intended to grant confidential treatment to the words in the parenthetical on the last line of that paragraph. If the words in the parenthetical are not afforded confidential treatment, the transmission costs that were granted confidential treatment can be determined. As such, Big Rivers requests the Commission grant rehearing of the November 21 order and grant confidential treatment to the words in the parenthetical on the last line in paragraph 1 on page 9 of the ACES study.

6. The Commission did not grant confidential treatment to Figure 12 on page 10 of the ACES study, which is a chart showing LMP differentials and the average LMP differential. However, the Commission did grant confidential treatment to the same average LMP differential amount in paragraph 1 on page 9 and in paragraph 1 on page 10 of the study. The chart of LMP differential amounts should be afforded confidential treatment for the same reasons. As such, Big Rivers requests the Commission grant rehearing of the November 21 order and grant confidential treatment to the chart of LMP differentials contained in Figure 12 on page 10 of the ACES study.

7. In the November 21 order, the Commission granted confidential treatment to the forecasted revenues and costs contained in Figure 13 on page 11 of the ACES study. It is unclear whether the Commission intended to grant confidential treatment to the

margins and capacity values in that figure. If confidential treatment is not afforded the margins and capacity values, the revenues and costs that were afforded confidential treatment can readily be determined. Additionally, the note to Figure 13 contains an LMP differential amount that was not afforded confidential treatment, but a different LMP differential amount on page 9 of the ACES study was afforded confidential treatment. As such, Big Rivers requests the Commission grant rehearing of the November 21 order and grant confidential treatment to the margins, capacity values, and LMP differential amount contained in Figure 13 on page 11 of the ACES study.

8. In the November 21 order, the Commission stated it was granting confidential treatment to the forecasted energy and demand rates contained in Figure 14 on page 12 of the ACES study. However, Figure 14 does not contain energy and demand rates. Figure 14 contains the same forecasted revenue, cost, margin, capacity value, and LMP differential as Figure 13, just for a different scenario, and the values in Figure 14 should be afforded confidential treatment for the same reasons similar values were afforded confidential treatment in other locations in the ACES study. As such, Big Rivers requests the Commission grant rehearing of the November 21 order and grant confidential treatment to the forecasted revenue, cost, margin, capacity value, and LMP differential values contained in Figure 14 on page 12 of the ACES study.

9. In the November 21 order, the Commission granted confidential treatment to a forecasted margin amount contained on line 2 of paragraph 3 on page 12 of the ACES study. The languages appearing after the word "effectively" in that sentence was not

afforded confidential treatment. Absent confidential treatment for that language, the margin amount in that sentence that was afforded confidential treatment can readily be estimated. As such, Big Rivers requests the Commission grant rehearing of the November 21 order and grant confidential treatment to the words after "effectively" in the sentence on line 2 of paragraph 3 on page 12 of the ACES study.

10. In the November 21 order, the Commission granted confidential treatment to the forecasted revenue values contained in Figures 17, 18, 19, 20, and 21 on pages 14-17 of the ACES study. Figures 17-21 also contain the same forecasted cost, margin, capacity value, and LMP differential amounts as Figure 13, just for different scenarios, and the values in Figures 17-21 should be afforded confidential treatment for the same reasons similar values were afforded confidential treatment in other locations in the ACES study. As such, Big Rivers requests the Commission grant rehearing of the November 21 order and grant confidential treatment to the forecasted revenue, cost, margin, capacity value, and LMP differential values contained in Figures 17, 18, 19, 20, and 21 on pages 14-17 of the ACES study.

WHEREFORE, Big Rivers respectfully requests that the Commission enter an order granting rehearing of the November 21, 2014, order and granting confidential treatment as requested above.

On this the 26th day of November, 2014.

Respectfully submitted,

James M. Miller
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Counsel for Big Rivers Electric Corporation

Certificate of Service

I certify that a true and accurate copy of the foregoing was or will be served by first class main, by Federal Express, or by hand delivery upon the persons listed on the accompanying service list, on or before the date the foregoing is filed with the Kentucky Public Service Commission.

On this the 26th day of November, 2014,

Counsel for Big Rivers Electric Corporation

Valuation and Risk Assessment of Energy and Capacity Sale to Nebraska Entities for Big Rivers Electric Corporation October 30, 2013

ACES
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DISCLAIMER

ACES has prepared this report based upon information provided by Big Rivers Electric Corporation (Big Rivers) and information obtained from other sources considered to be reliable. ACES makes no representations or warranties as to the accuracy of any data used in the preparation of this report. Big Rivers is cautioned that reliance upon this information and the underlying assumptions for conclusions, decisions, or strategies involves risks and uncertainties. ACES cannot give any assurances that actual results will be consistent with the projections in this report. This report contains confidential and proprietary information and should not be disclosed without the express written consent of Big Rivers and ACES.

1 Executive Summary

Big Rivers Electric Corporation ("Big Rivers") requested that ACES evaluate the potential margin available to cover Big Rivers fixed costs and identify risks associated with selling full requirements energy and capacity to the Northeast Nebraska Public Power District, the cities of Wayne, Wakefield, and South Sioux City, NE (collectively, "Nebraska Loads"). Big Rivers has been shortlisted by the Nebraska Loads to sell approximately 100 MW of capacity and associated energy to serve load from 2017 to 2026[1]. The Nebraska Loads have a composite load factor of approximately [redacted] The energy and capacity to service the Nebraska Loads would be delivered to the market interface of the Midcontinent Independent System Operator ("MISO") and Southwest Power Pool ("SPP") Regional Transmission Organizations. The Nebraska Loads would be responsible for Network Integrated Transmission Service, ancillary services, congestion and transmission losses on the SPP system. The pricing terms are based off an indexed rate equivalent to [redacted] of the future energy and demand tariff that the Nebraska Loads would pay if they continued with their current supplier, the Nebraska Public Power District ("NPPD"). A full list of indicative terms and conditions is contained in the Appendix including a reopener under a carbon regime. Big Rivers and the Nebraska Loads are currently working towards a binding contractual agreement by the end of 2013, subject to approval by Big Rivers' Chief Executive Officer, the boards of directors of both entities, the Kentucky Public Service Commission, and the Rural Utilities Service, among others.

The context for the sale is as follows: Beginning in 2014, due to loss of key aluminum smelting load, Big Rivers will have 850 MW of coal-fired generation available, with a similar amount of capacity in the MISO capacity market (Zone 6). The near-term MISO wholesale market environment does not support recovery of Big Rivers' generation fixed costs and the company will need to consider the short-term idling of generation resources if they are not able to find new customers to sell to. Big Rivers has responded to multiple load-serving entities' Requests For Proposals ("RFP") and other power supply negotiations over the last year and this transaction currently has the most potential to close and provide a future contribution to the fixed costs of Big Rivers.

Based upon the modeling assumptions stated in Section 3, the average forecasted sale price to the Nebraska Loads over the term of the transaction is approximately [redacted] Big Rivers' forecasted variable generation costs are [redacted] over the term of the transaction. Capacity payments from Big Rivers to the Nebraska Loads for roughly [redacted] of local generation capacity are [redacted] and administrative costs are forecasted to be approximately [redacted], yielding [redacted] in margin, making the transaction, before consideration of the cost of transmission or basis differential from Big Rivers to the NPPD interface, the equivalent of a sale of capacity from the units.

For the base case valuation, it was assumed the cost of the MISO transmission was offset by the negative Locational Marginal Price ("LMP") differential between Big Rivers' generation and the MISO NPPD Commercial Pricing Node ("CPNode"). Currently, the LMP differential is greater than the cost of the transmission and could be additional margin, but for conservatism was assumed $0/MWh additional margin in the base case. The transactions forecasted margin of almost [redacted] includes locational energy and capacity risks, as well as some unique risks. The major risk will be selling at an index of a rate that Big Rivers will not have the power to influence.

ACES modeled the economics of the sale under current market forecasts and model conditions to derive a valuation of the prospective contract. In addition, ACES generated several scenarios to quantify the

---

[1] Big Rivers' power supply commitments Percentage of Full Requirements Load Served by Big Rivers under the proposed transaction is provided in Section 2.

[2] Inputs provided by Big Rivers to ACES on September 25, 2013; output from Planning and Risk model is [redacted].

potential transaction impacts from risk inherent in the transaction. Those scenarios are outlined in detail in Section 2 and a summary of the results from the base case and each scenario are shown in Figure 1.

Figure 1

Case	2017-2026 Margins	Capacity $/MW-Year	Capacity $/MWh	Capacity $/kW-mo.
Base Case	[redacted]			
0% NPPD Rate Growth				
BREC Production Cost Up 25%				
Peak and Energy Down 10%				
LMP Differential to $0/MWh				
Wholesale Market Alternative				
NPPD Demand Charge Up				

If Big Rivers decides to proceed with contract negotiations with the Nebraska Loads, ACES recommends refreshing this analysis if any significant changes are made to the contract terms as well as evaluating the creditworthiness of each counterparty.

2 Overview of Risks

NPPD Rate Risk: Big Rivers would be selling at [redacted] of a future unknown indexed rate which cannot be hedged. Projections are for a small increase in the rate over the next eight years, consistent with NPPD's rate history.NPPD's current rates are similar to Big Rivers' rates with a full complement of load (prior to smelter exit) A scenario was developed that considers 0% rate increase for NPPD.

Big Rivers Generation Cost Risk: The major driver of Big Rivers variable production cost forecast is the price of coal in Western Kentucky. The current trajectory of coal prices from Wood Mackenzie North American Power Service has Illinois Basin increasing at a slightly faster rate than the coal utilized by NPPD from the Powder River Basin ("PRB"). A scenario was developed to increase Big Rivers variable production costs by 25% while not changing forecasted rates for NPPD.

Volumetric Load and Price Risk: The revenue forecast was developed based upon historical load shapes and assumed 1% load growth. Changes in consumer behavior or growth would alter the forecasted revenue. It is possible actual energy demand will exceed the forecasted peak and Big Rivers will have to procure additional MWs and transmission from the SPP market. This would increase the energy and demand payments to Big Rivers and the price risk is dependent upon wholesale prices at the time. Lower than forecasted peaks would also reduce payments to Big Rivers; however, Big Rivers would not incur the cost to generate those MWs. A scenario was developed that considers a peak demand and energy 10% below the base case valuation levels.

MISO Transmission Cost and Basis Payment Risk: Big Rivers would need to procure MISO firm point-to-point transmission to cover the peak load plus a planning reserve margin to deliver capacity to SPP less any local capacity Big Rivers acquires from the Nebraska Loads or other entities. ACES' forecast for MISO Transmission Service Request ("TSR") cost is based upon current tariff and MISO's forecast of cost increases for high voltage upgrades. Additional high voltage upgrades or cost overruns not currently forecasted by MISO could increase the cost for the MISO transmission. When scheduling the transaction, Big Rivers would continue to sell their generation in Kentucky and purchase from MISO at the NPPD interface CPNode to SPP. Over the last three years, this LMP has averaged [redacted] lower, with a range of $2/MWh to $16/MWh lower, than the LMP associated with Big Rivers' generation. To partially mitigate this risk, the indicative term sheet includes language that the Nebraska loads would [redacted] between the Big Rivers generation nodes and the MISO NPPD CPNode. To model this risk, a very conservative scenario was developed that assumes the LMP differential goes to $0/MWh and Big Rivers pays the full cost of the MISO transmission service (approximately [redacted]) with no recovery from the Nebraska Loads.

Wholesale Market Recovery: It is possible that the MISO wholesale market will recover and margins from the market would exceed the margins in this transaction. While this would not necessarily result in a financial loss to Big Rivers, in hindsight it would be a lost opportunity. A scenario was developed with a forecast of Indiana Hub prices for energy and capacity which shows the highest valuation of all the scenarios; however, these prices cannot be transacted beyond 2018 at this time for energy and are even more uncertain for capacity. As is ACES general practice, ACES assumed the price for capacity would be equal to a recently transacted capacity sale that ACES witnessed from another Member. If the capacity prices forecasted by Wood Mackenzie were utilized, the wholesale market scenario would yield higher margins. It should also be noted that the sale to the Nebraska Loads represents a small portion of Big Rivers' available generation position, and the remainder of the portfolio is currently subject to changes in the market, thus this hedge would provide diversity.

Transmission Availability: The transaction is contingent upon the parties successfully acquiring network service in SPP and firm MISO transmission from Big Rivers' resources.

Regulatory Risk: The Environmental Protection Agency, MISO, SPP, and the Federal Energy Regulatory Commission are just a few of the entities that could pose regulatory changes that alter the economics of this transaction and regulatory re-openers should be included in the final contract.

Agency Risk: Big Rivers will be the agent for this load in the wholesale market and should protect their liability for errors and omissions in the final contract.

While there are risks in a transaction of this nature that could decrease expected margins, there will also be opportunities to increase Big Rivers' margins. Some upside potential includes:

NPPD Demand Rate Increases More Than Forecasted: Through either capital expenditure (CapEx) increases or loss of load at NPPD, the NPPD forecasted demand rate could be understated. Fitch Ratings notes in their recent review of an NPPD sale of debt that Rating Sensitivities include "*LOSS OF WHOLESALE CUSTOMERS AND LOAD: The district's failure to make measureable near-term progress towards renewing expiring wholesale agreements and stabilizing long-term demand requirements is likely to result in negative rating action. Although potential termination remains over eight years away, the prevailing uncertainty of the district's service requirements is likely to increasingly frustrate long-term planning efforts.*"[3] Furthermore, Fitch notes that NPPD faces a risk of a load reduction: "*While not anticipated, considerable use of a load release provision in the wholesale contracts could reduce sales over time, further narrowing the base of which fixed costs must be recovered.*"[4] A scenario was developed with a higher demand charge.

Position Optimization: Big Rivers will have the flexibility to serve the load in the most economical manner. For example, Big Rivers could purchase additional SPP capacity and/or energy if it is more economical than generating and wheeling across MISO, saving on fuel and transmission costs.

Additional Load Potential: Other load-serving entities in Nebraska will be observing this transaction and there is potential for more to follow suit, whether with Big Rivers or other suppliers.

In summary, the valuation and scenarios to assess the major potential risks are presented below. The reduction in margins from the base case to any scenario could be added across multiple scenarios to determine an absolute worst case, be it however unlikely. If the forecasted wholesale MISO prices for energy from Wood Mackenzie North American Power Service come to fruition, then the best outcome appears to be to wait for a wholesale market recovery. If Big Rivers wants to gain margins sooner and for a ten-year term while developing a new long-term customer, and gain diversity while becoming less dependent on the market, then the Nebraska Loads present an interesting opportunity. Figure 2 displays the results of the base case valuation and scenarios described above.

Figure 2

Case	2017-2026 Margins	Capacity $/MW-Year	Capacity $/MWh	Capacity $/kW-mo.
Base Case	[redacted]			
0% NPPD Rate Growth				
BREC Production Cost Up 25%				
Peak and Energy Down 10%				
LMP Differential to $0/MWh				
Wholesale Market Alternative				
NPPD Demand Charge Up				

[3] See: Fitch Rates Nebraska Public Power District's 2013 Series A Refunding Revs 'A+'; Outlook Stable (http://www.businesswire.com/news/home/20131025005835/en/Fitch-Rates-Nebraska-Public-Power-Districts-2013, last accessed on October 30, 2013).
[4] Id.

3 Transaction Valuation Results

To value the transaction, ACES utilized market and historical data from the Nebraska Loads, NPPD, and the MISO market to forecast Big Rivers' margins above and beyond Big Rivers' variable cost of production for their generation fleet. The first step was to develop a load forecast through 2026, utilizing 2010-2012 actual load data as a base, and assuming that peak load and energy would to grow at [redacted] per year through 2026. Current load shapes were assumed to be unchanged. Figure 3 displays the Nebraska Loads' historical 2010-2012 (averaged) peak demand and energy.

Figure 3

2010-2012 Peak and Energy Summary

Nebraska Loads Actual Peak and Energy Summary (2010-2012)

Area	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
NEPPD												
Peak (MW)	41	40	37	30	31	36	41	40	34	34	36	38
Total Energy (MWh)	25,071	21,662	21,242	18,190	18,979	20,379	24,282	21,732	18,211	20,769	21,170	24,631
South Sioux City												
Peak (MW)	38	30	30	32	34	36	36	31	30	31	36	40
Total Energy (MWh)	20,565	15,687	17,164	17,384	19,479	20,197	20,554	18,078	15,954	17,157	18,694	21,881
Wakefield												
Peak (MW)	5	5	5	5	5	7	7	7	6	5	5	5
Total Energy (MWh)	3,144	2,823	2,940	2,818	3,346	3,672	4,177	3,947	3,299	3,212	2,852	3,076
Wayne												
Peak (MW)	9	9	8	7	8	10	11	11	11	8	8	8
Total Energy (MWh)	5,273	4,667	4,540	4,107	4,345	4,916	6,069	5,708	4,765	4,392	4,246	4,974
Total												
Peak (MW)	93	84	80	74	78	89	95	89	80	78	84	91
Total Energy (MWh)	54,053	44,840	45,885	42,499	46,149	49,164	55,082	49,464	42,229	45,529	46,961	54,562

Figure 4 displays the forecasted loads in 2017 assuming [redacted] annual load growth from the 2010-2012 base period.

Figure 4

2017 Monthly Peak and Energy Forecast

Forecasted Nebraska Loads Actual Peak and Energy Summary (2017)

Area	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
NEPPD	[redacted]											
Peak (MW)												
Total Energy (MWh)												
South Sioux City												
Peak (MW)												
Total Energy (MWh)												
Wakefield												
Peak (MW)												
Total Energy (MWh)												
Wayne												
Peak (MW)												
Total Energy (MWh)												
Total												
Peak (MW)												
Total Energy (MWh)												

The actual amount of load served by Big Rivers will vary in the first few years of the transaction as the Nebraska Loads begin the process of opting out of their wholesale contract with NPPD. The cities of South Sioux City, Wakefield and Wayne have the option of providing a three-year notice to NPPD by the end of 2013 permitting the purchase of [redacted] of their power supply from Big Rivers in 2017, [redacted] in 2018, [redacted] in 2019 and [redacted] in 2020. NeNPPD's ability to leave NPPD is staggered by one year due to a contractual obligation to provide one-year notice to the Nebraska G&T Cooperative. Accordingly, Figure 5 displays the percentage of load responsibility Big Rivers could have for each customer over the term of the transaction based on NeNPPD's interpretation of the NPPD contract termination language.

Figure 5
Percentage of Full Requirements Load Served by Big Rivers

Area	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
NeNPPD	[redacted]									
South Sioux										
Wakefield										
Wayne										

Figure 6 summarizes Big Rivers' forecasted peak load and annual energy responsibility over the term of the transaction if all of the Nebraska loads switch to Big Rivers.

Figure 6
2017-2026 Annual Peak and Energy Forecast to be served by Big Rivers

Variable	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Annual Peak (MW)	[redacted]									
Annual Energy (MWh)										

Based upon the projected hourly load profile, energy revenues were determined by multiplying the loads by the forecasted seasonal NPPD energy rate [redacted]. Figure 7 displays the current energy and demand rates of NPPD.

Figure 7
2013 NPPD Energy and Demand Rate Schedule

Variable	Rate
Summer Peak Energy Rate-kWh	$0.0335
Summer Off Peak Energy Rate -kWh	$0.0256
Winter Peak Energy Rate - kWh	$0.0307
Winter Off Peak Energy Rate - kWh	$0.0219
Summer Demand - kW	$13.4100
Winter demand - kW	$12.5400

Figure 8 displays the forecasted rate increases NPPD provided to their customers through 2020 and a forecast of rate increases assumed to [redacted] for 2021-2026. The second major payment to Big Rivers will be a demand payment for capacity. Based upon the current rate structure of NPPD, this will be billed monthly based upon a seasonal charge, June-September for summer and the remaining months for winter. An identical increased rate was applied to the demand rate as was utilized for energy.

Figure 8
NPPD Energy and Demand Rate Forecast

Rate Time of Day	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Increase		0.0%	4.2%	2.6%	1.5%	1.7%	0.9%	0.9%	[redacted]					
Summer Peak ($/MWh)	$33.45	$33.45	$34.85	$35.76	$36.30	$36.91	$37.25	$37.58	[redacted]					
Summer Off Peak ($/MWh)	$25.61	$25.61	$26.69	$27.38	$27.79	$28.26	$28.52	$28.77	[redacted]					
Winter Peak ($/MWh)	$30.69	$30.69	$31.98	$32.81	$33.30	$33.87	$34.17	$34.48	[redacted]					
Winter Off Peak ($/MWh)	$21.94	$21.94	$22.86	$23.46	$23.81	$24.21	$24.43	$24.65	[redacted]					
Summer Demand ($/MW)	$13,410	$13,410	$13,973	$14,337	$14,552	$14,799	$14,932	$15,067	[redacted]					
Winter Demand ($/MW)	$12,540	$12,540	$13,067	$13,406	$13,608	$13,839	$13,963	$14,089	[redacted]					

Big Rivers would include the following costs in the transaction: 1) Big Rivers variable production cost for their generation fleet from 2017-2026[5], (2) administrative costs from both the MISO and SPP RTOs, (3) a capacity payment of [redacted] for approximately [redacted] of local capacity from the Nebraska Loads, (4) and the cost of the MISO TSR to deliver to the MISO/SPP border. The MISO TSR cost is currently more than offset by the LMP differential between the source of Big Rivers' generation hedge and the point at which they will purchase from MISO (NPPD interface CP node) to deliver to the SPP border. Since Big Rivers joined MISO in 2010, the LMP differential between the Green Station and the NPPD CPNode has averaged a [redacted] implying that Big Rivers should be able to purchase energy for delivery to SPP at [redacted] than the LMP associated with Big Rivers' generation CPNode. For the purposes of the base case analysis, it was assumed that the net cost of the MISO TSR was [redacted]).

Figure 9 provides the projected production cost of Big Rivers' thermal fleet and the coal price forecast provided by Big Rivers.

Figure 9
Big Rivers Generation Fleet Variable Production Forecast

Variable	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Production Cost ($/MWh)	[redacted]									
Coal Price Forecast ($/MMBtu)	[redacted]									

Figure 10 displays the forecasted MISO transmission rate necessary for this transaction.

Figure 10
Forecasted MISO TSR Cost ($/MWh)

Variable	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Transmission Rate	[redacted]												
Scheduling & Dispatch	[redacted]												
Voltage Support	[redacted]												
System Upgrades	[redacted]												
New System Upgrades	[redacted]												
Market Ops Fees**	[redacted]												
Total Trans Costs	[redacted]												

As noted, Big Rivers has offered to acquire approximately [redacted] of local capacity from the Nebraska Loads at a cost of [redacted] The local capacity will be used in part to satisfy SPP's resource planning requirements. Figure 11 displays the total cost of the MISO transmission, less [redacted] of capacity that will be served directly from SPP. This assumes Big Rivers will serve a portion of the load from the SPP market, using the local capacity as a price hedge against SPP market purchases. If Big Rivers were to secure the entire transmission needs to serve the Nebraska Loads from MISO, this would result in a [redacted] reduction in expected margins over the life of the transaction.

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[5] Inputs to develop generation costs provided by Big Rivers on September 25, 2013; with outputs from ACES' Planning and Risk Model.

Figure 11
Forecasted MISO Transmission Capacity Needed and Total Costs

Variable	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Total MW Needed (Peak + 8%)	[redacted]									
Less Local Capacity (MW)										
Total MISO Trans Needed (MW)										
Total Cost of MISO Transmission										

Big Rivers will be selling their generation in Kentucky and purchasing at the MISO NPPD CPNode to deliver out of MISO, currently [redacted] lower LMP than Big Rivers' generation nodes. Figure 12 displays the historical average of the LMP differential between the two nodes, largely driven by significant wind farm additions on the western side of MISO and in SPP.

Figure 12
MISO LMP Differential

LMP Differential (7x24 Monthly Average)

[redacted]

Dec 2010 Feb 2011 Apr 2011 Jun 2011 Aug 2011 Oct 2011 Dec 2011 Feb 2012 Apr 2012 Jun 2012 Aug 2012 Oct 2012 Dec 2012 Feb 2013 Apr 2013 Jun 2013 Aug 2013 Oct 2013

MISO and SPP Administrative Costs

ACES assumed every MWh of forecasted sales would pay [redacted] in administrative fees between MISO and SPP, totaling [redacted] or the term of the transaction.

Base Case Transaction Valuation Summary

Figure 13 summarizes forecasted revenues and costs of the transaction on an annual net margin forecast by year. Effectively, this margin equates to a capacity payment to Big Rivers, which is the measure compared against the various scenarios. The value of that capacity payment is displayed in \$/MW-Year, \$/MWh, and \$/kW- mo.

Figure 13

Variable	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Energy Revenue	[redacted]									
Demand Revenue										
Capacity Payment to Loads										
Total Revenue										
Generation Costs										
Gross Margin										
Transmission Costs*										
Admin Fees										
Annual Net Margin										
Capacity Value $MW-year										
Capacity Value $MWh										
Capacity Value $ kW-mo.										

* assumes MISO TSR Costs and LMP Differential Payment [redacted]

4 Transaction Risks and Potential Mitigating Strategies

The transaction entails Big Rivers at [redacted] of NPPD's future rate. Publicly available data projections indicate a small increase in the NPPD wholesale rate over the next 8 years but factors could drive the rate lower. Some of the factors that could drive costs lower include: 1). Coal costs in the PRB could decline relative to current forecasts; 2). New load or load growth for NPPD could lead to a larger base of customers to spread fixed costs over, lowering the demand rate; 3). NPPD could decide to retire generation instead of embarking on a plan to comply with environmental regulations, potentially reducing costs and lowering NPPD rates, although this scenario is less likely because NPPD will still be responsible for covering the debt service associated with the plants even after retirement.

NPPD currently has excess generation and relies on the wholesale market for 25% of its energy sales. Price increases in the wholesale market would reduce the energy rate of NPPD; however, given this is a small portion of Big Rivers' forecasted length, the remaining Big Rivers portfolio would benefit from wholesale price increases. To assess the margin impact of these risks in isolation, ACES evaluated several scenarios.

Risk: NPPD energy and demand Rate experiences minimal growth or declines

Figure 14 displays the impact of NPPD rates not increasing above 2013 levels for the term of the deal. This scenario reduces margins by [redacted] in nominal dollars, effectively [redacted]

Figure 14

Variable	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Energy Revenue	[redacted]									
Demand Revenue										
Capacity Payment to Loads										
Total Revenue										
Generation Costs										
Gross Margin										
Transmission Costs*										
Admin Fees										
Annual Net Margin										
Capacity Value $MW-year										
Capacity Value $MWh										
Capacity Value $ kW-mo.										

* assumes MISO TSR Costs and LMP Differential Payment [redacted]

Risk: Fuel price risk

The major driver of Big Rivers' variable production cost forecast is the price of coal in Western Kentucky. The current trajectory of coal prices from Wood Mackenzie North American Power Service projects Illinois Basin Western Kentucky coal increasing at a slightly faster rate than PRB coal. Additionally, exports from the Illinois Basin ("ILB") coal are predicted to increase over time, potentially raising Big Rivers' fuel costs at a more rapid rate than NPPD fuel costs. In such a scenario, the margins on this transaction could diminish. While there is an ability to hedge fuel price risk on a 1-3 year basis (purchase Western Kentucky coal and sell equivalent volume of PRB futures), this is not possible for the entire term of the transaction.

The proposed transaction requires Big Rivers to sell power generated in Western Kentucky at a [redacted] to rates that are based on power generated by NPPD. NPPD's fuel mix based on 2012 is approximately 45% PRB coal, 34% nuclear, 4% hydro, 2% gas & oil, and 4% wind. In contrast, Big Rivers' generates electricity almost entirely with Western Kentucky coal. Prices of Western Kentucky coal closely track ILB coal prices. While all fuel prices are expected to increase over time, a widening price spread between NPPD's and Big Rivers' fuel sources has the potential to reduce Big Rivers' expected margins. Using Wood Mackenzie's long term coal forecast for 2017 – 2026, and utilizing PRB 8,800 Btu/lb prices vs. ILB 11,800 Btu/lb prices as a proxy for Western Kentucky, ILB prices are expected to increase at a higher rate than PRB prices. This would cause an increase in the cost of power generated by Big Rivers while NPPD's rates (based on fuel-price factors) would increase at a slower rate. In addition to PRB coal, NPPD also services about one-third of their load with nuclear. While nuclear fuel prices are expected to increase over this time period, the greater risk to rates in regards to nuclear power are increased regulatory costs, an advantage for Big Rivers.

Figure 15 shows PRB 8,800 Btu/lb vs. ILB 11,800 Btu/lb converted to MMBtu. ILB coal prices are expected to increase more than PRB coal prices. While ILB has a low cost of production and a high heat content, it also has the highest sulfur quality of all the major U.S. coal basins. Due to environmental regulations limiting SO2, many utilities have not utilized ILB coal in large quantities in the past. However, by 2016 when compliance with the Mercury Air Toxics Standards is implemented, nearly 100% of the coal-fired capacity in the US is expected to be scrubbed. This will lead to an increase in demand for ILB coal as utilities are able to switch away from higher cost, low sulfur coals.

Figure 15

[redacted]

Figure 16 shows the annual PRB and ILB forecasts in $/Ton as well as converted to $/MMBtu and $/MWh. The difference in $/MWh increases by roughly [redacted] over the time period of the proposed deal. Again, this example utilizes ILB as a proxy for Western Kentucky coals.

Figure 16

	ILB 11,800 Btu, 4.8 lbs			PRB 8,800 Btu, 0.8 lbs			
Year	$/Ton	$/MMBtu	$/MWh 10.5 HR	$/Ton	$/MMBtu	$/MWh 10.5 HR	Spread
2016	[redacted]						
2017							
2018							
2019							
2020							
2021							
2022							
2023							
2024							
2025							
2026							
2027							

The price risk between Big Rivers' cost to generate power and NPPD's rate would be challenging to hedge. The primary challenge is that NPPD's rate and thus Big Rivers' sales price is unknown until NPPD's monthly rate is determined. Hypothetically, Big Rivers could lock in the purchase price of Western Kentucky coal and sell a financial product to hedge PRB 8,800 and Uranium that are used to determine NPPD's rates. However, all of these markets lack the liquidity needed during the term of this deal and therefore Big Rivers would likely need to let the prices float and take the risk of not hedging the position. Big Rivers could develop a hedge strategy where the prompt two years are hedged on a rolling basis. This would reduce the risk of any short term price risk due to isolated events such as severe weather events, etc. Big Rivers could lock in the physical coal price while selling PRB coal futures. However, this would cause Big Rivers to post margin to a NYMEX account or utilize OTC swaps with an ISDA counterparty and could potential reduce expected margin dollars. The other concern would be the impact of PRB and Uranium prices on NPPD's rates. Further analysis would need to be done between the fuel prices and NPPD's rates to determine if this risk could be hedged effectively. To measure the impact of potential increases in Big Rivers' fuel costs relative to the increase in NPPD's future costs, a scenario in which Big Rivers variable production costs increased by [redacted] was evaluated. As indicated in Figure 17 in such a scenario, Big Rivers would experience a [redacted] reduction in margins over the term of the sale. Big Rivers would be netting an overall [redacted] on the transaction due to demand payments, but the effective value of the capacity is reduced [redacted] from the base case.

Figure 17

Variable	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Energy Revenue	[redacted]									
Demand Revenue										
Capacity Payment to Loads										
Total Revenue										
Generation Costs										
Gross Margin										
Transmission Costs*										
Admin Fees										
Annual Net Margin										
Capacity Value $MW-year										
Capacity Value $MWh										
Capacity Value $ kW-mo.										

* assumes MISO TSR Costs and LMP Differential Payment [redacted]

Risk: Uncertain volume of load sales

The revenue forecast was developed based upon historical load shapes and assumed [redacted] load growth. Changes in consumer behavior or growth would alter the forecasted revenue. Behind-the-Meter generation, like community solar projects, would need to be carefully addressed in the contract-writing phase of the transaction. Additionally, Big Rivers will procure capacity one year ahead with SPP for a forecasted peak. It is possible actual energy demand will exceed the forecasted peak and Big Rivers' will have to procure the additional MWs from the SPP market. This would increase the energy and demand payments to Big Rivers and the price risk is dependent upon wholesale prices at the time. Lower than forecasted peaks would also reduce payments to Big Rivers. To assess this impact a scenario was developed that reduced peak demand and energy by [redacted] over the entire term of the transaction. Accordingly, margins were reduced by about [redacted], as shown in Figure 18.

Figure 18

Variable	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Energy Revenue	[redacted]									
Demand Revenue										
Capacity Payment to Loads										
Total Revenue										
Generation Costs										
Gross Margin										
Transmission Costs*										
Admin Fees										
Annual Net Margin										
Capacity Value $MW-year										
Capacity Value $MWh										
Capacity Value $ kW-mo.										

* assumes MISO TSR Costs and LMP Differential Payment [redacted]

Risk: Uncertain LMP differential

While the base case assumed the LMP differential and the cost of transmission would offset each other, it is possible the basis could decline further and the MISO transmission could result in a net cost to Big Rivers. Accordingly, the indicative term sheet includes language to protect Big Rivers' against basis [redacted]. In this situation, the Nebraska Loads would [redacted]. While unlikely, Figure 19 illustrates a scenario where the LMP differential declines from [redacted] and Big Rivers has to pay the full cost of the MISO transmission service. If the congestion component becomes positive, Big Rivers can expect that an Auction Revenue Right would be available for the TSR costs, which will mitigate exposure for positive congestion between Big Rivers and the SPP interface. The cost of the LMP forecast declining to [redacted] is [redacted] over the ten-year term, with a [redacted] erosion in Big Rivers' margin over the term; however, the Nebraska loads would cover [redacted] of this exposure. It is important to note that this risk cannot be hedged well, as the MISO Financial Transmission Rights (FTR) market clears for one year forward at a time, and long-term, bilateral hedging options to FTRs are very limited.

Figure 19

Variable	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Energy Revenue	[redacted]									
Demand Revenue										
Capacity Payment to Loads										
Total Revenue										
Generation Costs										
Gross Margin										
Transmission Costs										
Admin Fees										
Annual Net Margin										
Capacity Value $MW-year										
Capacity Value $MWh										
Capacity Value $ kW-mo.										

ACES' Transmission group uses a forward-looking LMP model, historical actual LMP values, and auction clearing prices to forecast basis expectations in the future. Previous analysis of the areas can be combined to give an approximation of our forward expectations at this time, in order to assess the viability of this transaction. Based upon the data available at this time, our forecast is for total basis (energy, congestion and losses, the absolute difference in LMP) between BREC.WILSON1 and the MISO NPPD interface to be approximately [redacted] for 2017-2019. Forecasting nodal prices beyond this range is impossible as potential transmission upgrades are just not known that far into the future. For forecasting purposes only, by 2027 this spread is seen as declining to the [redacted] standpoint. This view is based upon the expectations that stubbornly high congestion will be relieved by projects not yet envisioned to be built in the next decade.

While most scenarios were provided to consider downside risk, as noted there is also upside potential in the transaction for Big Rivers. Accordingly, ACES prepared a hypothetical scenario assuming that NPPD embarked on $900 million in capital expenditures to address required upgrades to its generation fleet. A recent rating agency report indicated that NPPD capital cost expenditures *"extending to 2016-2020 could be as much as $900 million, but will depend largely on the district's ability to renew its expiring wholesale contracts"*.[6] ACES assumed [redacted] debt financing, a [redacted] debt cost rate, and a [redacted] levelized cost of service for amortization purposes to derive a higher demand charge for NPPD. As indicated in Figure 20, in such a scenario a [redacted] improvement in margins would occur, all other assumptions unchanged.

Figure 20

Variable	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Energy Revenue	[redacted]									
Demand Revenue										
Capacity Payment to Loads										
Total Revenue										
Generation Costs										
Gross Margin										
Transmission Costs*										
Admin Fees										
Annual Net Margin										
Capacity Value $MW-year										
Capacity Value $MWh										
Capacity Value $ kW-mo.										

* assumes MISO TSR Costs and LMP Differential Payment [redacted]

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6 See: Fitch Rates Nebraska Public Power District's 2013 Series A Refunding Revs 'A+'; Outlook Stable (http://www.businesswire.com/news/home/20131025005835/en/Fitch-Rates-Nebraska-Public-Power-Districts-2013, last accessed on October 30, 2013).

5 Wholesale Market Alternatives

While the Nebraska Loads represent one opportunity to start replacing load in the Big Rivers portfolio, another strategy is for Big Rivers to wait for a recovery in wholesale energy market. Figure 21 displays potential revenues based upon a Wood Mackenzie energy price forecast and a recent capacity transaction for 2017-2021 around [redacted] escalated at [redacted] per year for the remainder of the period. This scenario would result in a [redacted] improvement in margins above the base case. It is important to note, however, that there is no ability in the current market to transact beyond 2018 and thus there is no ability to lock in the potential wholesale market improvement, unlike what the sale to the Nebraska Loads may provide. As discussed, ACES assumed capacity prices at a recently transacted price; however, using the Wood Mackenzie projection for capacity prices would result in higher projected margins.

Figure 21

Variable	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Energy Revenue	[redacted]									
Demand Revenue										
Capacity Payment to Loads										
Total Revenue										
Generation Costs										
Gross Margin										
Transmission Costs*										
Admin Fees										
Annual Net Margin										
Capacity Value $MW-year										
Capacity Value $MWh										
Capacity Value $ kW-mo.										

* assumes MISO TSR Costs and LMP Differential Payment [redacted]

6 Appendix

INDICATIVE PROPOSAL
CONFIDENTIAL

Term Sheet – Big Rivers Electric Corporation

Pending the complete and expected answers to questions of NPPD about their contract terms through December 31, 2021, Big Rivers will provide NeNPPD and any combination of the other RFP participants "Clients" a contract on terms as follows:

__Terms and Pricing__

Product: Partial requirements supply beginning on January 1, 2017* through December 31, 2021 in accordance with the Clients' and NPPD's current contract termination provisions. Beginning January 1, 2022, Big Rivers will supply all requirements of Clients and will deliver the capacity and energy to SPP/MISO Interface. Big Rivers will be the sole provider for Client except as provided below in Resource provisions.

*Big Rivers understands that the terms for NeNPPD are delayed one year due to its inability to provide notice of termination to NPPD by December 31, 2013.

Term: 10 years ending December 31, 2026. Following contract expiration, Big Rivers is willing to offer an ongoing two-year evergreen option with a two-year termination notification for either party. Big Rivers is also willing to consider voting-Membership as an option for Clients at the end of the term, taking power at the then-active Big Rivers' tariff rate, assuming Big Rivers has adequate capacity to serve Clients long-term.

Price: Big Rivers will index its charges under this contract on non-irrigation load and charge [redacted] of NPPD's charges for demand and energy under NPPD's applicable published tariffs for all requirements demand and energy on NPPD's GFPS rate.

Big Rivers recognizes that about 15 MWs of irrigation pumping load have been able to historically avoid paying monthly demand charges by shifting their load to avoid system peaks. Big Rivers will both 1) price the irrigation load separately from the indexed load discussed above and 2) develop a substitute program, to be determined and proposed by Big Rivers in the next 6 months, whereby the shifting of irrigation load to low cost hours can still provide value to Big Rivers and Clients.

__Resources__

Renewable Energy: In the event the Clients desire to purchase a long term contract for renewable energy, then the customers' will have the right to purchase and take delivery of an amount no more than [redacted] unless they are required to purchase by new laws or regulations. Clients will use the renewable energy only as a substitute for Big Rivers' energy. Client will continue to purchase all capacity needs from Big Rivers pursuant to this agreement. Big Rivers will schedule the renewable energy contracts on the Clients behalf.

Capacity purchase of local generation: Beginning January 1, 2017, Big Rivers will purchase the available capacity rights of customers' generation at a rate of [redacted] per kW-month for qualifying capacity credits as defined by SPP (or other applicable RTO/ISO).

WAPA Allocation: NeNPPD and South Sioux City both have WAPA allocations of hydro power. Big Rivers will manage the WAPA contract for the term of this agreement in an effort to optimize value to Clients. WAPA Allocation will be optimized by scheduling the power into the wholesale market on Clients behalf. Net Benefits (or cost) of WAPA contract optimization will be passed through to Clients.

Economic Development Incentive Rate: Clients will have the option of offering prospective new customers the rate applicable under this contract or if Big Rivers has an economic development incentive rate in place, Client may offer the Big Rivers' economic development incentive rate in a similar fashion to Big Rivers' Members for use in recruiting economic development prospects to their territory. Clients agree that if new prospects are priced under Big Rivers' economic development incentive rate, their rates in the future will be based on Big Rivers' existing rate structure, not the rates applicable to this agreement.

Right to Build Future Generation: Big Rivers currently has no desire or intention to build generation in Nebraska; however, if Big Rivers desires to build new generation in Nebraska at some point in the future, Clients will have the Right of First Refusal to build such generation at its cost and sell to Big Rivers at that cost as long as Clients remains a customer of Big Rivers.

<u>Transmission and Ancillary Services</u>

Transmission: Big Rivers will take responsibility for the delivery of power to MISO/SPP Interface. Included in this will be Big Rivers' responsibility to assume the basis differential between Big Rivers' generation and the MISO/SPP interface. Also, Big Rivers will assume the cost of MISO Point-to-Point transmission. Client and Big Rivers agree to allocate any price differential change equally among the two parties if the basis differential between Big Rivers' generation and the NPPD interface deviates from the 2015 average in any year of the agreement, by more than [redacted] in either party's favor. Client will assume responsibility for SPP (or other RTO/ISO in which load resides, if applicable) Transmission service, congestion and losses, and all Ancillary Services.

Clients and Big Rivers agree that this agreement, as well as future load additions, will be contingent on firm transmission availability in both MISO and SPP.

Big Rivers and Clients agree that integration into MISO may result in a mutual benefit for both parties. Parties agree to work cooperatively to investigate the possibility of integration. If possibilities exist, parties agree to pursue integration only if both parties agree that mutual benefits exist.

Transmission Studies: Big Rivers will coordinate transmission impact studies for this arrangement on Clients' behalf. Any work completed by Big Rivers will be completed on a no-fee basis; however, any work completed by and external entity (ISO/RTO, etc.) will be billed to Client with no additional fee or markup applied. If this contract comes to fruition and definitive documents are completed, Big Rivers will reimburse Client for the external costs.

<u>Other</u>

Future Environmental Rules: Big Rivers will offer to 1) bill the customers' directly for any future costs associated with carbon legislation or regulation or other expense incurred as a direct proportion of the energy or capacity supplied to customers or 2) provide a 2 year termination provision. Big Rivers will also have a 2-year contract termination option in the event carbon legislation or regulation is passed.

Contract: Big Rivers and Clients desire to have one contract between Big Rivers and the Clients collectively. Clients will work to determine how best to accommodate this request. Big Rivers will work with the Clients to provide a draft contract as soon as possible and a final contract for execution by Monday, December 16, 2013. Once the contract is executed the customers will be responsible for initiating all contract termination notices to NPPD.

Credit Assurances: Big Rivers and Clients agree that credit assurances may be required by either party in the future. If, by January 1, 2016, Big Rivers has not attained investment grade credit ratings by at least two of the three credit rating agencies, Big Rivers and Clients will negotiate acceptable credit assurances at that time.

Any final agreement shall be subject to the negotiation of mutually acceptable credit terms and conditions. This offering is preliminary and is intended to set forth certain basic terms and to serve as a basis for further discussion and negotiations between the Parties with respect to the potential Agreement described herein. This proposal does not contain all matters upon which agreement must be reached in order for the transaction to be completed. The matters set forth herein are not intended to and do not constitute a binding agreement of the Parties nor do they establish any obligation of the Parties with respect to the Agreement, and this proposal may not be relied upon by a Party as the basis for a contract by estoppel or otherwise. A binding agreement will arise only upon the negotiation, execution and delivery of mutually satisfactory definitive agreements and the satisfaction of the conditions set forth therein, including completion of due diligence and the approval of such agreements by the respective governing body (ies), management and board of each Party, which approval shall be in the sole subjective discretion of the respective governing body (ies), management and their respective board.