COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

| | | |
|---|---|---|
| ELECTRONIC APPLICATION OF BIG RIVERS ELECTRIC CORPORATION FOR ENFORCEMENT OF RATE AND SERVICE STANDARDS | ) | CASE NO. 2019-00269 |

# CITY OF HENDERSON, KENTUCKY, AND HENDERSON UTILITY COMMISSION d/b/a HENDERSON MUNICIPAL POWER & LIGHT'S RESPONSES TO COMMISSION STAFF'S INITIAL REQUEST FOR INFORMATION

**BEFORE THE PUBLIC SERVICE COMMISSION**
**IN THE MATTER OF**
**BIG RIVERS ELECTRIC CORPORATION**
**APPLICATION OF BIG RIVERS ELECTRIC CORPORATION FOR ENFORCEMENT OF RATE AND SERVICE STANDARDS**
**CASE NO. 2019-269**

## VERIFICATION

I, Seth W. Brown, verify, state and affirm that the data request responses filed with this verification for which I am listed as a witness are true and accurate to the best of my knowledge, information and belief formed after a reasonable inquiry.

Seth W. Brown

COMMONWEALTH OF KENTUCKY )
COUNTY OF HENDERSON )

SUBSCRIBED AND SWORN to before me by Seth W. Brown on this the 10th day of August, 2020.

Notary Public, Georgia State at Large
My Commission Expires: 1/8/2023

LISA D. PARKER
NOTARY
EXPIRES
GEORGIA
January 8, 2023
PUBLIC
BARTOW COUNTY

**BEFORE THE PUBLIC SERVICE COMMISSION**
**IN THE MATTER OF**
**BIG RIVERS ELECTRIC CORPORATION**
**APPLICATION OF BIG RIVERS ELECTRIC CORPORATION FOR**
**ENFORCEMENT OF RATE AND SERVICE STANDARDS**
**CASE NO. 2019-269**

**VERIFICATION**

I, Christopher Heimgartner, verify, state and affirm that the data request responses filed with this verification for which I am listed as a witness are true and accurate to the best of my knowledge, information and belief formed after a reasonable inquiry.

______________________________
Christopher Heimgartner

COMMONWEALTH OF KENTUCKY )
COUNTY OF HENDERSON )

SUBSCRIBED AND SWORN to before me by Christopher Heimgartner on this the 10th day of August, 2020.

TAMMY KONSLER
NOTARY PUBLIC
ID NO. 579781
MY COMMISSION EXPIRES 5/28/2021
STATE AT LARGE, KY.

Tammy Konsler
Notary Public, Kentucky State at Large
My Commission Expires: 5-28-2021
Notary ID #: 579781

**BEFORE THE PUBLIC SERVICE COMMISSION**
**IN THE MATTER OF**
**BIG RIVERS ELECTRIC CORPORATION**
**APPLICATION OF BIG RIVERS ELECTRIC CORPORATION FOR ENFORCEMENT OF RATE AND SERVICE STANDARDS**
**CASE NO. 2019-269**

## VERIFICATION

I, Barbara Moll, verify, state and affirm that the data request responses filed with this verification for which I am listed as a witness are true and accurate to the best of my knowledge, information and belief formed after a reasonable inquiry.

Barbara a. Moll

Barbara Moll

COMMONWEALTH OF KENTUCKY )
COUNTY OF HENDERSON )

SUBSCRIBED AND SWORN to before me by Barbara Moll on this the 10th day of August, 2020.

TAMMY KONSLER NOTARY PUBLIC ID NO. 579781 MY COMMISSION EXPIRES 5/28/2021 STATE AT LARGE, KY.

Tammy Konsler
Notary Public, Kentucky State at Large
My Commission Expires: 5-28-2021
Notary ID #: 579781

**BEFORE THE PUBLIC SERVICE COMMISSION**
**IN THE MATTER OF**
**APPLICATION OF BIG RIVERS ELECTRIC CORPORATION FOR ENFORCEMENT OF RATE AND SERVICE STANDARDS**
**CASE NO. 2019-269**

**VERIFICATION**

I, Brad Bickett, verify, state and affirm that the data request responses filed with this verification for which I am listed as a witness are true and accurate to the best of my knowledge, information and belief formed after a reasonable inquiry.

Brad Bickett
Brad Bickett

COMMONWEALTH OF KENTUCKY )
COUNTY OF HENDERSON )

SUBSCRIBED AND SWORN to before me by Brad Bickett on this the 11th day of August, 2020.

TAMMY KONSLER
NOTARY PUBLIC
ID NO. 579781
MY COMMISSION EXPIRES 5/28/2021
STATE AT LARGE, KY.

Tammy Konsler
Notary Public, Kentucky State at Large
My Commission Expires: 5-28-2021
Notary ID #: 579781

**Item 1)** **Refer to the Direct Testimony of Brad Bickett (Bickett Testimony), pages 5-6, regarding the lack of authority of Big Rivers Electric Corporation (BREC) to act as a Market Participant in the Midcontinent Independent System Operator (MISO) markets on Henderson's behalf with regard to Henderson's load and Station Two. State whether Henderson notified BREC of Henderson's objections to BREC's registering the Station Two units with MISO or committing those units to take service from MISO prior to February 1, 2019. If so, provide copies of any communications from Henderson to BREC that would reflect such notice.**

**Response)** Yes. See attached letter from Henderson to Big Rivers dated September 30, 2010, along with related correspondence which was attached to that letter. As referenced in the September 30, 2010, letter, Henderson notified Big Rivers as early as April 12, 2010, that if Big Rivers were to join the Midcontinent Independent System Operator (MISO), then Big Rivers would have to do so independently of Henderson. Henderson was not under any obligation to decide how, or whether, to pursue MISO membership. A May 27, 2010, email from former HMP&L General Manager Gary Quick to Cheryl Bredenbeck of MISO states clearly that Henderson did not object to the <u>separate</u> registration of the parties' relative shares of Station Two capacity. As a party to the Station Two contracts, Big Rivers had an obligation to obtain Henderson's written consent to register the City's Station Two units in MISO alongside Big Rivers' other assets. Big Rivers did not obtain Henderson's consent, written or otherwise.

**Witness)** **Brad Bickett**

HMP&L HENDERSON MUNICIPAL POWER & LIGHT

September 30, 2010

Mr. Mark Bailey
Big Rivers Electric Corporation
PO Box 24
Henderson, KY 42419-0024

REF: MISO Registration – Big Rivers
PSC Case No. 2010-00043

Dear Mark:

Thank you for your September 27 email (copy attached) concerning the pending MISO registration for Big Rivers. Since receiving your September 22 letter (copy attached) concerning the MISO registration a couple of events have taken place. Henderson has held discussions with The Energy Authority (TEA) which is located in Jacksonville, Florida, and this past Monday, Henderson and TEA participated in a conference call with representatives of MISO.

Based upon the statements made by MISO representatives during the conference call, it is Henderson's understanding that an officer of Big Rivers has certified to MISO that Big Rivers has the authority or right to register all of the capacity and related energy of Henderson Station Two under Big Rivers' name. Big Rivers has apparently also certified that it has the authority or right to act as the MISO Market Participant for Henderson's annual reserved capacity and related energy. As the asset owner, Henderson is not aware of any existing verbal or written authorizations that allow Big Rivers to register Henderson Station Two, which apparently included Henderson's annual reserved capacity and related energy, with MISO. Also, Henderson has not authorized Big Rivers to act as a MISO Market Participant for Henderson. Henderson is not aware of any existing documents between Henderson and Big Rivers that grant Big Rivers the authority to register Station Two with MISO without the written consent from Henderson. As we explained to Big Rivers and MISO, since our first meeting with you on April 12 concerning the possibility of Big Rivers joining MISO, Henderson has considered becoming a Market Participant or retaining a third party to act as our Market Participant. Henderson has also indicated an interest in registering Station Two with MISO since that was one of the options MISO presented to Henderson.

**Attachment 1 for Henderson's Response to Commission Staff 1**

HMP&L

As the owner of Station Two, Henderson does not agree with or approve the Big Rivers proposed MISO registration filing for Station Two and we do not agree with Big Rivers' proposal to act as Market Participant for Henderson's reserved capacity and related energy. We suggest that Big Rivers and MISO correct the proposed Big Rivers' pending registration filing concerning Henderson's Station Two and Big Rivers' proposed market participation to represent Henderson.

Sincerely,

Gary Quick
General Manager

cc: Mr. Ray Beaver, MISO
Ms. Cheryl Bredenbeck, MISO
Mr. Kevin Vannoy, MISO
Mr. Sam Doaks, Sr., TEA
Mr. Bill Clarke, TEA
Mr. Jeff R. Derouen, PSC
Mr. Wayne Thompson, HMP&L

Attachments:
1) May 27, 2010 email to Cheryl A. Brendenbeck
2) September 22, 2010 Mark Bailey Letter
3) September 23, 2010 email to Cheryl A. Brendenbeck
4) September 24, 2010 & September 27, 2010 emails G. Quick and M. Bailey

**Wayne Thompson**

**From:** Cheryl A. Bredenbeck [cbredenbeck@midwestiso.org]
**Sent:** Friday, May 28, 2010 7:40 AM
**To:** Gary Quick
**Cc:** Wayne Thompson
**Subject:** RE: Big Rivers to register Henderson Question

Gary,

Thank you for your prompt reply. This is exactly the information I needed to know. Our modelers are working with Big Rivers next week and I want to ensure the modeling submissions are consistent with your preferences expressed to us and to Big Rivers. We look forward to working with you (and TEA) in the future.

Cheryl

---

**From:** Gary Quick [mailto:gquick@hmpl.net]
**Sent:** Thursday, May 27, 2010 5:10 PM
**To:** Cheryl A. Bredenbeck
**Cc:** Wayne Thompson
**Subject:** RE: Big Rivers to register Henderson Question

Hi Cheryl:

Yes, we talked with Mark Bailey yesterday morning at 8:00 am at the Big Rivers Office Building. We informed Mark and his staff that Henderson was agreeable to Big Rivers registering Henderson's 105 MW (as of June 1) and Big Rivers 207 MW separately rather than merely registering the 312 MW. You will need to visit with Mark, but I did not get the impression the separate registration was a problem for Big Rivers. We also informed Mark and his staff that Henderson was visiting with TEA to represent Henderson in the near future. Does this provide you with the information you need??

Thanks, Gary

---

**From:** Cheryl A. Bredenbeck [mailto:cbredenbeck@midwestiso.org]
**Sent:** Thursday, May 27, 2010 4:31 PM
**To:** Gary Quick
**Cc:** Wayne Thompson
**Subject:** Big Rivers to register Henderson Question

Gary,

Thank you for meeting us again last week. I am writing to ask if you had a chance to leave a message for Mark Bailey of Big Rivers informing them that you are fine with Big Rivers registering Henderson assets for this first modeling registration cycle?

Have a great memorial weekend!

Regards,

Cheryl

Cheryl Bredenbeck
Director, Transmission Services
Midwest ISO

Big Rivers
ELECTRIC CORPORATION

201 Third Street
P.O. Box 24
Henderson, KY 42419-0024
270-827-2561
www.bigrivers.com

Rec. 9/23/2010 AM
@ HMP&L

September 22, 2010

Mr. Gary Quick
General Manager
Henderson Municipal Power & Light
P. O. Box 8
Henderson, KY 42419-0008

Dear Gary:

As you may know, Big Rivers' hearing before the Public Service Commission in its case seeking authority to transfer functional control of its transmission system to Midwest Independent Transmission System Operator, Inc. ("Midwest ISO") concluded September 15, 2010. In order to implement Big Rivers' scheduled December 1, 2010, integration into the Midwest ISO, Big Rivers submitted Commercial Model data to the Midwest ISO on September 15, 2010, and on September 22, 2010, submitted two required certifications regarding the registration of the Station Two generation asset and the City of Henderson load. Pursuant to those submissions, Big Rivers will act as the Market Participant on behalf of the City of Henderson load and Station Two. This designation will have no impact on Big Rivers' performance of its contractual obligations under its agreements with the City of Henderson regarding Station Two. Please let me know if you have any questions, or if we can provide you further information.

Sincerely yours,

Mark A. Bailey

Mark A. Bailey
President and CEO
Big Rivers Electric Corporation

**Gary Quick**

| | |
|---|---|
| **From:** | Gary Quick |
| **Sent:** | Thursday, September 23, 2010 12:54 PM |
| **To:** | 'Cheryl A. Bredenbeck' |
| **Cc:** | Wayne Thompson; 'Sam H. Doaks'; Randall Redding; 'Haynes, Greg'; Snell, Virginia; 'Mark Bailey' |
| **Subject:** | BREC Letter |
| **Attachments:** | BREC LTR 9-22.pdf |

Good Morning Cheryl:

On May 27 of this year I sent you an email at 5:10pm concerning Henderson Municipal Power and Light's intentions in the event Big Rivers Electric Cooperation became a member of MISO. Henderson has also held several meetings with you, MISO staff, and Big Rivers concerning the various options available to Henderson related to how Henderson could participate in MISO. Our position concerning participation in MISO has not changed since our last communication.

Attached is a letter I received this morning from Mr. Bailey at Big Rivers concerning the Henderson Station Two generation units. Henderson needs to know how MISO is planning to register the Henderson units. As stated in the attached letter, Big Rivers informed us this morning that it will act as the Market Participant on behalf of the City of Henderson, which is not consistent with our position and what we have clearly stated to MISO and Big Rivers.

Before we respond to Big Rivers, we need to know what MISO and Big Rivers have done, if anything, regarding the Henderson Station Two capacity, energy, and Market Participation. As we explained to MISO and Big Rivers, Henderson has always intended to register its annual reserved capacity and the related energy. Furthermore, we also informed MISO and Big Rivers that Henderson was considering two options regarding future Market Participation; first, Henderson would request MISO's approval to become a Market Participant or second, Henderson would retain an existing external Market Participant to represent Henderson.

Please let me know the details of how Big Rivers is requesting to join MISO regarding the registration of Henderson's Station Two units and the Market Participant responsibilities.

In advance, thank you. Gary

BREC LTR 9-22.pdf
(400 KB)

**Gary Quick**

**From:** Mark Bailey [Mark.Bailey@bigrivers.com]
**Sent:** Monday, September 27, 2010 3:14 PM
**To:** Gary Quick
**Cc:** cbredenbeck@midwestiso.org
**Subject:** RE: BREC Letter

Hello Gary:

You asked in the following e-mail message of September 24, 2010, how Big Rivers submitted the registration request for the Station Two capacity and related energy. Big Rivers, as Market Participant, has submitted to Midwest ISO registration forms for Station Two Unit 1 (153 MW) and Unit 2 (159 MW). The HMP&L load is registered as a part of Big Rivers' load. This was accomplished on or about September 15, 2010, as required by Midwest ISO to assure integration of Big Rivers into Midwest ISO by December 1, 2010, prior to expiration on December 31, 2010, of Midwest ISO Attachment RR Contingency Reserve service to Big Rivers for all generators operated by it. As I noted in my letter of September 22, 2010, this registration will have no negative impact on Big Rivers' performance of its contractual obligations under its agreements with the City of Henderson regarding Station Two. Please let me know if we may provide you further information.

Mark

---

**From:** Gary Quick [mailto:gquick@hmpl.net]
**Sent:** Friday, September 24, 2010 11:46 AM
**To:** Mark Bailey
**Cc:** 'Cheryl A. Bredenbeck'; Wayne Thompson
**Subject:** FW: BREC Letter

Good Morning Mark:

I plan to respond to your September 22 letter concerning MISO, but after I received your letter I had several questions for MISO. Below is an email from Cheryl and she responded to some of my questions. However, please note her comment below concerning my questions about the registration of Station Two capacity and related energy. Cheryl suggested that I contact you; can you let me know how Big Rivers submitted the registration request for the Station Two capacity and related energy? As we discussed with you and your staff, if HMP&L participates in MISO we will register our annual reserved capacity and related energy. We assume Big Rivers has registered its annual allocated capacity and related energy. We have a meeting today with TEA and I'm sure they will need to have this information as they go forward as HMP&L's Market Participant.

In advance, thanks for your help. Gary

---

**From:** Cheryl A. Bredenbeck [mailto:cbredenbeck@midwestiso.org]
**Sent:** Friday, September 24, 2010 10:22 AM
**To:** Gary Quick
**Cc:** Wayne Thompson; 'Sam H. Doaks'; Randall Redding; 'Haynes, Greg'; Snell, Virginia; 'Mark Bailey'
**Subject:** RE: BREC Letter

Hi Gary,

I do have a copy of your referenced May 27th e-mail. As you recall at the time of those April to May discussions, Big Rivers was preparing for a September 1 integration (that was later postponed) and the timeline for Market Participants to register assets located in the Balancing Authority was June 15th, two and one-half months before the initial planned Big Rivers integration. The postponed integration date is now December 1 with the corresponding deadline for Market Participants (new and existing) to register assets falling the same two and one-half months before, or September 15. If you look at the materials Midwest ISO provided and reviewed in our visit to your offices back on April 27th, Slide 27 of those materials contains the registration process and due dates for Market Participant registration materials to be submitted.

In order for a Big Rivers Balancing Authority to join the Midwest ISO market all generation and load must be registered by Market Participants. Each Market Participant submits asset registration forms and becomes financially responsible for the assets it registers. As you recognize in your message below, under the Midwest ISO process the only way assets can be registered is by a Market Participant. On September 15 Midwest ISO only received the registration from an existing Market Participant – namely Big Rivers. Your May 27th e-mail confirmed that you were agreeable to Big Rivers registering the City's assets. Therefore, we have processed the Big Rivers September 15th Registration accordingly.

As we discussed back in April, the City of Henderson, as an asset owner, can certainly register once you've met the requirements of a Market Participant or elect to have a different Market Participant register these assets on your behalf in a future modeling cycle. The timing of the registration needs to be compliant with the attached Midwest ISO model deadlines presentation. These deadlines are also posted on our website. We would be happy to assist you in better understanding that Market Participant and asset registration process if you would like.

With regard to specific questions as to how the capacity and energy was registered you would need to contact Mr. Bailey at Big Rivers.

Sincerely,

Cheryl

---

**From:** Gary Quick [mailto:gquick@hmpl.net]
**Sent:** Thursday, September 23, 2010 12:54 PM
**To:** Cheryl A. Bredenbeck
**Cc:** Wayne Thompson; 'Sam H. Doaks'; Randall Redding; 'Haynes, Greg'; Snell, Virginia; 'Mark Bailey'
**Subject:** BREC Letter

Good Morning Cheryl:

On May 27 of this year I sent you an email at 5:10pm concerning Henderson Municipal Power and Light's intentions in the event Big Rivers Electric Cooperation became a member of MISO. Henderson has also held several meetings with you, MISO staff, and Big Rivers concerning the various options available to Henderson related to how Henderson could participate in MISO. Our position concerning participation in MISO has not changed since our last communication.

Attached is a letter I received this morning from Mr. Bailey at Big Rivers concerning the Henderson Station Two generation units. Henderson needs to know how MISO is planning to register the Henderson units. As stated in the attached letter, Big Rivers informed us this morning that it will act as the Market Participant on behalf of the

City of Henderson, which is not consistent with our position and what we have clearly stated to MISO and Big Rivers.

Before we respond to Big Rivers, we need to know what MISO and Big Rivers have done, if anything, regarding the Henderson Station Two capacity, energy, and Market Participation. As we explained to MISO and Big Rivers, Henderson has always intended to register its annual reserved capacity and the related energy. Furthermore, we also informed MISO and Big Rivers that Henderson was considering two options regarding future Market Participation; first, Henderson would request MISO's approval to become a Market Participant or second, Henderson would retain an existing external Market Participant to represent Henderson.

Please let me know the details of how Big Rivers is requesting to join MISO regarding the registration of Henderson's Station Two units and the Market Participant responsibilities.

In advance, thank you. Gary

**Item 2) Refer to the Direct Testimony of Brad Bickett (Bickett Testimony), page 5 and BREC's Application Exhibit 14, pages 71-73 of 123. Explain whether "[a]ny other costs associated with Station Two which are not included in paragraphs (a) through (g) hereof" would include MISO fees and charges.**

**Response)** Disputed MISO fees and charges would not be included. Section 6.3 of the Power Sales Contract, as amended in 2005, provides a non-exhaustive list of Station Two operating and maintenance costs to be allocated between the parties on the basis of Henderson's annual capacity reservation and the amount of capacity allocated to Big Rivers. Section 6.3(h), as amended, which contains the language referenced in the request, appears to be a catchall provision to allow for operating and maintenance costs not specifically listed in Subsections (a) through (g) and otherwise properly attributable to Station Two. Subsection (h) does not allow for the inclusion of costs such as the disputed MISO transmission fees, which are not related to the operation or maintenance of Station Two. Henderson has consistently contested responsibility for MISO fees and objected to their inclusion in Big Rivers' proposed operating plans.

**Witness) Brad Bickett**

**Item 3)** **Refer to the Bickett Testimony, page 6, lines 2-3. Provide in more detail the MISO-related issues that were first brought to Henderson's attention by BREC in 2017. If this communication was memorialized, provide a copy of such communication.**

**Response)** To avoid any potential confusion regarding the content of my testimony, I would like to clarify that my reference to 2017 was intended to communicate the approximate date when Henderson initially learned that Big Rivers was in possession of data concerning the past and future value of profitable Excess Henderson Energy in the MISO market. Prior to that time, communications between Henderson and Big Rivers regarding MISO were limited to issues related to Henderson's load as opposed to the Station Two generating asset. Attached to this response is a series of emails between me and Mark Eacret regarding the profitable energy - or what Mr. Eacret referred to as "in the money" energy - which was the subject of a dispute then pending before the Henderson Circuit Court in Civil Action No. 09-CI-00693. Henderson is not aware of which, if any, other issues related to Station Two - as opposed to Henderson's load – were not brought to Henderson's attention.

**Witness)** **Brad Bickett**

**Brad Bickett**

| | |
|---|---|
| **From:** | Brad Bickett |
| **Sent:** | Wednesday, May 3, 2017 4:01 PM |
| **To:** | Eacret, Mark J |
| **Subject:** | RE: Contact Information |

Mark,

We have looked at the forward pricing curves, but have not performed an analysis at this point.

Brad Bickett
Reliability Compliance Manager
Henderson Municipal Power & Light (HMP&L)
100 Fifth Street, Henderson, KY 42420
Phone: (270) 826-2726 Fax: (270) 826-9650

**From:** Eacret, Mark J [mailto:Mark.Eacret@bigrivers.com]
**Sent:** Wednesday, May 03, 2017 3:34 PM
**To:** Brad Bickett
**Subject:** RE: Contact Information

Brad,

I meant to ask you about the forward-looking part of your analysis:

1. Bob mentioned that you had an IndyHub forward curve. Is that what you used, or did you adjust it to get to Station Two prices?
2. How did you shape the monthly forward prices to get to daily or hourly prices?
3. Did you use "Reservation – Load" as opposed to "Exhibit A"?
4. Did you use the same "in-the-money day" approach that you used for the historical?

We did the forward-looking part using a production cost model called Plexos. If you could give me your production cost estimates, we could try to run it with those numbers and "Reservation – Load".

**From:** Eacret, Mark J
**Sent:** Wednesday, May 03, 2017 3:17 PM
**To:** 'bbickett@hmpl.net' <bbickett@hmpl.net>
**Subject:** Contact Information

Brad,

Here is my contact information.

**Attachment 1 for Henderson's Response to Commission Staff 3**

Mark J. Eacret
Vice President Energy Services
Big Rivers Electric Corporation
Office – 270.844.6126
Cell – 636.579.8740

**Brad Bickett**

**From:** Brad Bickett
**Sent:** Friday, May 5, 2017 1:20 PM
**To:** Eacret, Mark J
**Subject:** RE: July09-Feb17 DA HMPL vs DA MISO System Avg.xlsx

Mark,

On another subject, I am looking for information about the requirements for generation capacity and reserve margin pertaining to HMP&L demand in MISO. Would you be able to discuss this information or direct me to someone?

Brad

**From:** Eacret, Mark J [mailto:Mark.Eacret@bigrivers.com]
**Sent:** Friday, May 05, 2017 10:54 AM
**To:** Brad Bickett
**Subject:** FW: July09-Feb17 DA HMPL vs DA MISO System Avg.xlsx

Brad,

One of the differences between our calculations and yours for 2009-2017 was the market price used. We used the Station Two price while you used a MISO system average. We compared the two and found that they are pretty close. The Station Two price is a little over 1% higher on average over the period that we examined.

I've attached the raw data.

**From:** Tutor, Elizabeth
**Sent:** Friday, May 05, 2017 10:14 AM
**To:** Eacret, Mark J <Mark.Eacret@bigrivers.com>
**Subject:** July09-Feb17 DA HMPL vs DA MISO System Avg.xlsx

Here is the price comparison. HMP1 DA LMPs are slightly higher than the MISO system Average. I have a separate file of the Hub prices that make up the system average if you want to see that let me know.

Thanks,
Elizabeth

## Brad Bickett

| | |
|---|---|
| **From:** | Eacret, Mark J <Mark.Eacret@bigrivers.com> |
| **Sent:** | Monday, May 8, 2017 7:04 AM |
| **To:** | Brad Bickett |
| **Cc:** | Berry, Bob |
| **Subject:** | Book3 (002).xlsx |
| **Attachments:** | Book3 (002).xlsx |

Brad,

Attached is BREC's calculation of the value of in-the-money EHE from July of 2009 through February of 2017. There are a few differences from your approach:

1. BREC tested each hour against variable cost, as opposed to your approach testing against each day.
2. BREC used the MISO market price at Station Two, rather than the MISO system average price that you used. (I sent you a comparison of the two price points last week).
3. The BREC spreadsheet values all EHE in columns A-E and in-the-money EHE in columns F-K.

This is a summary page. There will be someone available at Wednesday's meeting to discuss in more detail.

Mark

**Brad Bickett**

| | |
|---|---|
| **From:** | Eacret, Mark J <Mark.Eacret@bigrivers.com> |
| **Sent:** | Monday, May 8, 2017 7:08 AM |
| **To:** | Brad Bickett |
| **Cc:** | Berry, Bob |
| **Subject:** | Book2 (003).xlsx |
| **Attachments:** | Book2 (003).xlsx |

Brad,

Attached is BREC's calculation of the value of in-the-money EHE from April '17 through December of 2023. There are a couple of differences between the approach here and the approach in the 2009-2017 calculation:

1. We are using an estimate of BREC's production cost, rather than Henderson's
2. We are using the "Exhibit A" approach, rather than the "Reservation – Load" approach

This is a summary spreadsheet. We will have someone available to discuss the detail on Wednesday.

Mark

**Brad Bickett**

| | |
|---|---|
| **From:** | Eacret, Mark J <Mark.Eacret@bigrivers.com> |
| **Sent:** | Monday, May 8, 2017 9:45 AM |
| **To:** | Brad Bickett |
| **Cc:** | Berry, Bob; Parsley, Marlene |
| **Subject:** | FW: HMPL Issues briefing book chapter on Capacity Shortage |
| **Attachments:** | Station Two Capacity Sales Revenue PY 13_14 thru 17_18.xlsx; HMPL Capacity Requirements summary as of 2017_2018.docx |

Brad,

Attached are some documents addressing your question from last week on MISO capacity requirements.

The spreadsheet compares Henderson's MISO capacity requirements and its capacity resources beginning with the 2013 planning year. There was no MISO capacity auction prior to that planning year, so determining a market price for the 2011 and 2012 planning years would be subjective.

The word document walks through the MISO requirements and calculations associated with the 2017/2018 planning year as an example.

We'll have someone at our Wednesday meeting that can walk through the detail and any questions that you have,

Mark

## Brad Bickett

|  |  |
|---|---|
| **From:** | Brad Bickett |
| **Sent:** | Tuesday, May 9, 2017 3:24 PM |
| **To:** | Eacret, Mark J |
| **Cc:** | Ken Brooks |
| **Subject:** | RE: 2009 to 2017 EHE Calculations and 2017-2023 EHE Calculations |
| **Attachments:** | Station two energy - July 17 2009 Feb 2017 4-24-17.pdf |

Mark,

Attached is a PDF copy of the data that I put together. If you need anything else, just let me know.

Brad

**From:** Eacret, Mark J [mailto:Mark.Eacret@bigrivers.com]
**Sent:** Tuesday, May 09, 2017 3:09 PM
**To:** Brad Bickett
**Cc:** Ken Brooks
**Subject:** RE: 2009 to 2017 EHE Calculations and 2017-2023 EHE Calculations

Brad,

Ken is welcome to participate. Please forward the invite to him.

Could you bring copies of your calculation of the 2009-2017 EHE in-the-money value? I only have one and I've got notes all over it.

**From:** Brad Bickett [mailto:bbickett@hmpl.net]
**Sent:** Tuesday, May 09, 2017 10:38 AM
**To:** Eacret, Mark J <Mark.Eacret@bigrivers.com>
**Cc:** Ken Brooks <kbrooks@hmpl.net>
**Subject:** RE: 2009 to 2017 EHE Calculations and 2017-2023 EHE Calculations

Mark,

I think it may be helpful if Ken Brooks would also attend this meeting. He is the Interim Power Production Director for Henderson and I talked to him about it earlier. He is available.

Thanks,
Brad

-----Original Appointment-----
**From:** Vickie.King@bigrivers.com [mailto:Vickie.King@bigrivers.com] **On Behalf Of** Eacret, Mark J
**Sent:** Tuesday, May 09, 2017 8:33 AM
**To:** Tutor, Elizabeth; Braunecker, Duane; Brad Bickett; Parsley, Marlene
**Cc:** Berry, Bob; Jones, Charles
**Subject:** 2009 to 2017 EHE Calculations and 2017-2023 EHE Calculations

**When:** Wednesday, May 10, 2017 9:00 AM-11:00 AM (UTC-06:00) Central Time (US & Canada).
**Where:** HQ Conference Room 4A Between Production & Fuels Area

All,

The intent of the meeting is to review each of the approaches:

Brad – Henderson calculations of 2009-2017
Elizabeth – BREC calculations of 2009-2017
Duane – BREC calculations of 2017-2023

Please prepare whatever materials you think would be helpful for the others to see/understand. A computer projection screen will be available.

Brad, we'll be sending you summary sheets for Elizabeth and Duane's work later today.

---

**Brad Bickett**

| | |
|---|---|
| **From:** | Eacret, Mark J <Mark.Eacret@bigrivers.com> |
| **Sent:** | Tuesday, May 16, 2017 7:32 AM |
| **To:** | Brad Bickett |
| **Cc:** | Tutor, Elizabeth; Chris Heimgartner; Berry, Bob |
| **Subject:** | RE: Henderson excess energy data - economic hourly data |

Thanks, Brad

Elizabeth dropped your production costs into her model, which resulted in 1,224,292 MWh and margins of $9,755,013. The $470K difference between her margins and yours was driven by:

Volume – ($80K)
Price - 630K
VOM - ($80K)

Your average price is $37.15/MWh and Elizabeth's is $36.63/MWh. We aren't going to tie exactly, but we might want to give the prices some thought so that we understand what is driving the difference in the modeling. Elizabeth will send you her summary.

**From:** Brad Bickett [mailto:bbickett@hmpl.net]
**Sent:** Monday, May 15, 2017 3:25 PM
**To:** Eacret, Mark J <Mark.Eacret@bigrivers.com>
**Cc:** Tutor, Elizabeth <Elizabeth.Tutor@bigrivers.com>; Chris Heimgartner <cheimgartner@hmpl.net>
**Subject:** Henderson excess energy data - economic hourly data

Mark,

From our discussion last Wednesday, see revised historical figures attached in excel and PDF. Changes include the following:

- MISO system Day Ahead prices were replaced by the provided Day Ahead ExPost LMP prices at Station Two generators.
- Henderson variable cost increased due to addition of average expenses for disposal, landfill, and FGD (Fiscal year 2016 amounts used for current year)

Let me know if there are any comments or questions.

Brad

## Brad Bickett

| | |
|---|---|
| **From:** | Brad Bickett |
| **Sent:** | Thursday, May 18, 2017 2:18 PM |
| **To:** | Tutor, Elizabeth |
| **Cc:** | Eacret, Mark J |
| **Subject:** | RE: Henderson excess energy data - economic hourly data |
| **Attachments:** | Station two energy - July 17 2009 March 2017 5-18-17 economic hours.xlsx |

Elizabeth,

Attached is my updated summary...

- March 2017 data has been added
- Energy market administration fees are included

Note: All energy is valued at Day Ahead price and market admin fees are included with energy production cost for the hourly test against market value.

Brad

**From:** Tutor, Elizabeth [mailto:Elizabeth.Tutor@bigrivers.com]
**Sent:** Thursday, May 18, 2017 10:16 AM
**To:** Brad Bickett
**Cc:** Eacret, Mark J; Chris Heimgartner
**Subject:** RE: Henderson excess energy data - economic hourly data

Hi Brad,

Attached are the MISO Market Admin Rates as well as the March DA/RT LMPs and the Generation Awards for Station Two.

Please let me know if you have any questions or need anything further.

Thank you,

*Elizabeth R Tutor; MISO Settlement Supervisor; Big Rivers Corporation; 201 3rd Street Henderson, KY 42420; (p) 270-844-6177, (c) 270-577-3243, (f) 270-827-2101*

**From:** Brad Bickett [mailto:bbickett@hmpl.net]
**Sent:** Wednesday, May 17, 2017 9:22 AM
**To:** Tutor, Elizabeth <Elizabeth.Tutor@bigrivers.com>
**Cc:** Eacret, Mark J <Mark.Eacret@bigrivers.com>; Chris Heimgartner <cheimgartner@hmpl.net>
**Subject:** RE: Henderson excess energy data - economic hourly data

Elizabeth,

Henderson production cost for March 2017 averaged $29.85 per MWh, and includes variable expenses for coal, emissions, reagent lime, disposal, landfill, and FGD.

It will help if you can send the LMP data for March because I will not have to access each MISO daily report. Also, if you send the MISO admin fee data, I will include that expense in my calculations.

Thank you,

Brad

**From:** Brad Bickett
**Sent:** Tuesday, May 16, 2017 1:05 PM
**To:** Tutor, Elizabeth
**Cc:** Eacret, Mark J
**Subject:** Re: Henderson excess energy data - economic hourly data

Elizabeth,

You are correct; I did not include admin fee. I am out of office today but will send you data for march when I get back tomorrow.

Thank you,

Brad B

On May 16, 2017, at 11:06 AM, Tutor, Elizabeth <Elizabeth.Tutor@bigrivers.com> wrote:

> Attached is my calculation summary. I think one of our price differences is that I am removing the MISO admin fees from the MISO revenue. If you would like me to send you the MISO Admin Rates, please let me know.
>
> Also, since the future value of EHE analysis starts with April 2017. Could we add March 2017 so that they line up? Please send me your Variable Cost numbers for March and I can send you the Station Two LMPs.
>
> Thank you,
>
> *Elizabeth R Tutor; MISO Settlement Supervisor; Big Rivers Corporation; 201 3rd Street Henderson, KY 42420; (p) 270-844-6177. (c) 270-577-3243. (f) 270-827-2101*
>
> **From:** Eacret, Mark J
> **Sent:** Tuesday, May 16, 2017 7:32 AM
> **To:** Brad Bickett <bbickett@hmpl.net>
> **Cc:** Tutor, Elizabeth <Elizabeth.Tutor@bigrivers.com>; Chris Heimgartner <cheimgartner@hmpl.net>; Berry, Bob <Bob.Berry@bigrivers.com>
> **Subject:** RE: Henderson excess energy data - economic hourly data
>
> Thanks, Brad

Elizabeth dropped your production costs into her model, which resulted in 1,224,292 MWh and margins of $9,755,013. The $470K difference between her margins and yours was driven by:

Volume – ($80K)
Price - 630K
VOM - ($80K)

Your average price is $37.15/MWh and Elizabeth's is $36.63/MWh. We aren't going to tie exactly, but we might want to give the prices some thought so that we understand what is driving the difference in the modeling. Elizabeth will send you her summary.

**From:** Brad Bickett [mailto:bbickett@hmpl.net]
**Sent:** Monday, May 15, 2017 3:25 PM
**To:** Eacret, Mark J <Mark.Eacret@bigrivers.com>
**Cc:** Tutor, Elizabeth <Elizabeth.Tutor@bigrivers.com>; Chris Heimgartner <cheimgartner@hmpl.net>
**Subject:** Henderson excess energy data - economic hourly data

Mark,

From our discussion last Wednesday, see revised historical figures attached in excel and PDF. Changes include the following:

- MISO system Day Ahead prices were replaced by the provided Day Ahead ExPost LMP prices at Station Two generators.
- Henderson variable cost increased due to addition of average expenses for disposal, landfill, and FGD (Fiscal year 2016 amounts used for current year)

Let me know if there are any comments or questions.

Brad

<July 2009-Feb2017 Economic EHE Resv-Load using HMPL variable cost v2 - Summary Only.xlsx>

**Brad Bickett**

**From:** Tutor, Elizabeth <Elizabeth.Tutor@bigrivers.com>
**Sent:** Thursday, May 18, 2017 10:16 AM
**To:** Brad Bickett
**Cc:** Eacret, Mark J; Chris Heimgartner
**Subject:** RE: Henderson excess energy data - economic hourly data
**Attachments:** July 2009 - March 2017 MISO Market Admin and Schedule 24 Rates.xlsx; March 2017 DA RT LMPs and Gen Awards.xlsx

Hi Brad,

Attached are the MISO Market Admin Rates as well as the March DA/RT LMPs and the Generation Awards for Station Two.

Please let me know if you have any questions or need anything further.

Thank you,

*Elizabeth R Tutor; MISO Settlement Supervisor; Big Rivers Corporation; 201 3rd Street Henderson, KY 42420; (p) 270-844-6177, (c) 270-577-3243, (f) 270-827-2101*

**From:** Brad Bickett [mailto:bbickett@hmpl.net]
**Sent:** Wednesday, May 17, 2017 9:22 AM
**To:** Tutor, Elizabeth <Elizabeth.Tutor@bigrivers.com>
**Cc:** Eacret, Mark J <Mark.Eacret@bigrivers.com>; Chris Heimgartner <cheimgartner@hmpl.net>
**Subject:** RE: Henderson excess energy data - economic hourly data

Elizabeth,

Henderson production cost for March 2017 averaged $29.85 per MWh, and includes variable expenses for coal, emissions, reagent lime, disposal, landfill, and FGD.

It will help if you can send the LMP data for March because I will not have to access each MISO daily report. Also, if you send the MISO admin fee data, I will include that expense in my calculations.

Thank you,

Brad

**From:** Brad Bickett
**Sent:** Tuesday, May 16, 2017 1:05 PM
**To:** Tutor, Elizabeth
**Cc:** Eacret, Mark J
**Subject:** Re: Henderson excess energy data - economic hourly data

Elizabeth,

You are correct; I did not include admin fee. I am out of office today but will send you data for march when I get back tomorrow.

Thank you,

Brad B

On May 16, 2017, at 11:06 AM, Tutor, Elizabeth <Elizabeth.Tutor@bigrivers.com> wrote:

Attached is my calculation summary. I think one of our price differences is that I am removing the MISO admin fees from the MISO revenue. If you would like me to send you the MISO Admin Rates, please let me know.

Also, since the future value of EHE analysis starts with April 2017. Could we add March 2017 so that they line up? Please send me your Variable Cost numbers for March and I can send you the Station Two LMPs.

Thank you,

*Elizabeth R Tutor; MISO Settlement Supervisor; Big Rivers Corporation; 201 3rd Street Henderson, KY 42420; (p) 270-844-6177, (c) 270-577-3243, (f) 270-827-2101*

**From:** Eacret, Mark J
**Sent:** Tuesday, May 16, 2017 7:32 AM
**To:** Brad Bickett <bbickett@hmpl.net>
**Cc:** Tutor, Elizabeth <Elizabeth.Tutor@bigrivers.com>; Chris Heimgartner <cheimgartner@hmpl.net>; Berry, Bob <Bob.Berry@bigrivers.com>
**Subject:** RE: Henderson excess energy data - economic hourly data

Thanks, Brad

Elizabeth dropped your production costs into her model, which resulted in 1,224,292 MWh and margins of $9,755,013. The $470K difference between her margins and yours was driven by:

Volume – ($80K)
Price - 630K
VOM - ($80K)

Your average price is $37.15/MWh and Elizabeth's is $36.63/MWh. We aren't going to tie exactly, but we might want to give the prices some thought so that we understand what is driving the difference in the modeling. Elizabeth will send you her summary.

**From:** Brad Bickett [mailto:bbickett@hmpl.net]
**Sent:** Monday, May 15, 2017 3:25 PM

**To:** Eacret, Mark J <Mark.Eacret@bigrivers.com>
**Cc:** Tutor, Elizabeth <Elizabeth.Tutor@bigrivers.com>; Chris Heimgartner <cheimgartner@hmpl.net>
**Subject:** Henderson excess energy data - economic hourly data

Mark,

From our discussion last Wednesday, see revised historical figures attached in excel and PDF. Changes include the following:

- MISO system Day Ahead prices were replaced by the provided Day Ahead ExPost LMP prices at Station Two generators.
- Henderson variable cost increased due to addition of average expenses for disposal, landfill, and FGD (Fiscal year 2016 amounts used for current year)

Let me know if there are any comments or questions.

Brad

<July 2009-Feb2017 Economic EHE Resv-Load using HMPL variable cost v2 - Summary Only.xlsx>

## Brad Bickett

**From:** Eacret, Mark J <Mark.Eacret@bigrivers.com>
**Sent:** Monday, June 5, 2017 2:15 PM
**To:** Brad Bickett
**Subject:** RE: HMPL Issues briefing book chapter on Capacity Shortage

Understood, thanks

**From:** Brad Bickett [mailto:bbickett@hmpl.net]
**Sent:** Monday, June 05, 2017 2:09 PM
**To:** Eacret, Mark J <Mark.Eacret@bigrivers.com>
**Subject:** RE: HMPL Issues briefing book chapter on Capacity Shortage

Yes.. However, I have not verified any of the capacity figures.

Brad

**From:** Eacret, Mark J [mailto:Mark.Eacret@bigrivers.com]
**Sent:** Monday, June 05, 2017 2:04 PM
**To:** Brad Bickett
**Subject:** RE: HMPL Issues briefing book chapter on Capacity Shortage

Thanks, Brad

So the SEPA reference isn't to all years, just the year (Planning Year 14/15) in which MISO didn't allow us to count SEPA for resource adequacy?

**From:** Brad Bickett [mailto:bbickett@hmpl.net]
**Sent:** Monday, June 05, 2017 1:54 PM
**To:** Eacret, Mark J <Mark.Eacret@bigrivers.com>
**Subject:** RE: HMPL Issues briefing book chapter on Capacity Shortage

Mark,

Sorry for the delayed response. In regard to the spreadsheet comment on capacity cost, (Bilateral Agreement) that was a reference to Section 2.2 of the System Reserves Agreement. On the question about SEPA capacity, although it was not compensated by MISO in the voluntary annual planning resource auction, SEPA was firm capacity available to and used by HMP&L for the purpose of resource adequacy. Let me know if you have any other questions, and feel free to give me a call if you want to discuss.

Brad
270-724-0850

**From:** Eacret, Mark J [mailto:Mark.Eacret@bigrivers.com]
**Sent:** Wednesday, May 31, 2017 8:30 AM
**To:** Brad Bickett
**Subject:** RE: HMPL Issues briefing book chapter on Capacity Shortage

Sure, enjoy your time off.

I know that Bob and Chris want to get these issues finalized, so if you could get back with me as soon as you could on Monday, I would appreciate it.

**From:** Brad Bickett [mailto:bbickett@hmpl.net]
**Sent:** Wednesday, May 31, 2017 8:25 AM
**To:** Eacret, Mark J <Mark.Eacret@bigrivers.com>
**Subject:** Re: HMPL Issues briefing book chapter on Capacity Shortage

Mark,

I am out of the office this week on vacation. I would like to get back to you on Monday about this question if that will work for you.

Brad B

On May 31, 2017, at 8:14 AM, Eacret, Mark J <Mark.Eacret@bigrivers.com> wrote:

> Brad,
>
> We are working on reconciling some HMPL numbers that Chris gave to Bob last Friday to ours. I'm working on the MISO capacity issue.
>
> BREC had calculated a cost of $203K to cover HMPL's MISO capacity requirements since 2013. HMPL's number is zero. In the spreadsheet that Chris gave Bob, there is a note that says "Bilateral Agreement". Bob told me that Chris said that the BREC calculations didn't properly account for HMPL's SEPA allocation.
>
> The spreadsheets that we reviewed in our meeting (attached) reflected HMPL's SEPA allocation. Can you help me with this?
>
> Mark
>
> **From:** Eacret, Mark J
> **Sent:** Monday, May 08, 2017 9:45 AM
> **To:** 'bbickett@hmpl.net' <bbickett@hmpl.net>
> **Cc:** Berry, Bob <Bob.Berry@bigrivers.com>; Parsley, Marlene <Marlene.Parsley@bigrivers.com>
> **Subject:** FW: HMPL Issues briefing book chapter on Capacity Shortage
>
> Brad,
>
> Attached are some documents addressing your question from last week on MISO capacity requirements.

The spreadsheet compares Henderson's MISO capacity requirements and its capacity resources beginning with the 2013 planning year. There was no MISO capacity auction prior to that planning year, so determining a market price for the 2011 and 2012 planning years would be subjective.

The word document walks through the MISO requirements and calculations associated with the 2017/2018 planning year as an example.

We'll have someone at our Wednesday meeting that can walk through the detail and any questions that you have,

Mark

<Station Two Capacity Sales Revenue PY 13_14 thru 17_18.xlsx>

<HMPL Capacity Requirements summary as of 2017_2018.docx>

**Brad Bickett**

**From:** Eacret, Mark J <Mark.Eacret@bigrivers.com>
**Sent:** Wednesday, June 7, 2017 7:01 AM
**To:** Sebourn, Michael
**Cc:** Brad Bickett; Tutor, Elizabeth; Berry, Bob
**Subject:** RE: Henderson Follow-Up Meeting

Mike,

We'll have personnel familiar with the historical view from both BREC and HMPL. Do you want anyone available for questions on the future value?

If you come across any questions on either approach prior to Friday's meeting, please pass them along. We might be able to get you an answer prior to the meeting or will be prepared to answer it by then.

Mark

**From:** Sebourn, Michael [mailto:Michael.Sebourn@lge-ku.com]
**Sent:** Tuesday, June 06, 2017 4:57 PM
**To:** Eacret, Mark J <Mark.Eacret@bigrivers.com>
**Subject:** RE: Henderson Follow-Up Meeting

Hi Mark,

Thanks for your message.

1. Bob Berry sent the files supporting the future value and I just replied with a request for the supporting files for the historical view.

2. Does 9:30 Central time work for you on Friday?

3. It would be great if someone could walk us through the analysis. I think we understand the future value pretty well, so we'll probably want to focus on the historical view. But hopefully, we can get a basic understanding from the supporting files before we come on Friday.

Mike

**Michael Sebourn**
Manager, Generation Planning | LG&E and KU
220 W. Main St., Louisville, KY 40202
O: 502-627-2994 | M: 502-403-8117 | F: 502-217-2020
michael.sebourn@lge-ku.com

**From:** Eacret, Mark J [mailto:Mark.Eacret@bigrivers.com]
**Sent:** Tuesday, June 06, 2017 5:15 PM
**To:** Sebourn, Michael <Michael.Sebourn@lge-ku.com>
**Subject:** Henderson Follow-Up Meeting

Mike,

I understand that you will be traveling to Henderson this Friday (6/9) to complete your review of some calculations around Henderson Excess Energy. A few questions:

1. Do you need any additional materials for your work prior to Friday?
2. What time would you like to meet on Friday?
3. Would you just like to ask questions, or would you like to have someone walk you through the analysis?

Let me know what would work best for you.

Mark J. Eacret
Vice President Energy Services
Big Rivers Electric Corporation
Office – 270.844.6126
Cell – 636.579.8740

**Item 4)** **Refer to the Bickett Testimony, pages 12-14. Provide any documentation Henderson possesses that shows Henderson's system peak demand and Station Two peak hour demand.**

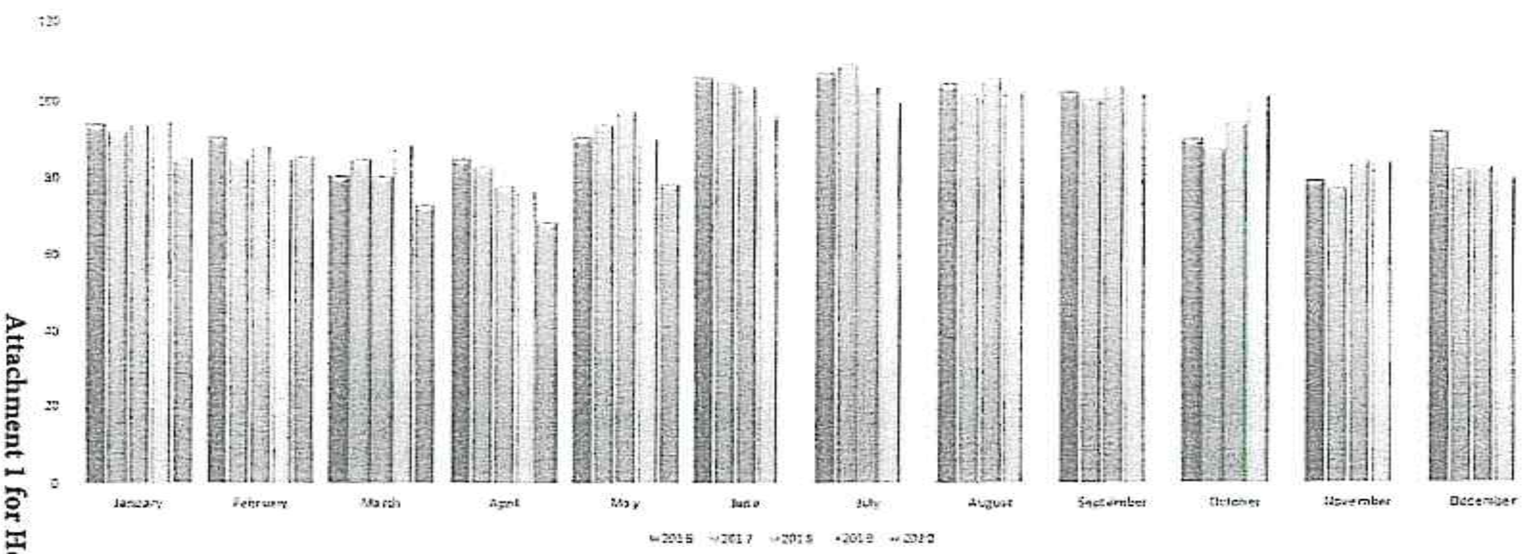
**Response)** See attached.

**Witness)** **Brad Bickett**

## NET SYSTEM PEAKS BY YEAR & MONTH
### 2013-2020

| Year | January | February | March | April | May | June | July | August | September | October | November | December | Highest Peak of Year |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2013 | 89 | 90 | 85 | 83 | 94 | 104 | 108 | 108 | 105 | 94 | 84 | 93 | 108 |
| 2014 | 102 | 96 | 89 | 77 | 97 | 106 | 105 | 108 | 104 | 93 | 90 | 84 | 108 |
| 2015 | 100 | 97 | 88 | 76 | 90 | 104 | 109 | 106 | 104 | 87 | 76 | 82 | 109 |
| 2016 | 94 | 91 | 81 | 85 | 91 | 106 | 107 | 105 | 103 | 91 | 80 | 93 | 107 |
| 2017 | 92 | 85 | 85 | 83 | 94 | 105 | 110 | 102 | 101 | 88 | 78 | 83 | 110 |
| 2018 | 94 | 88 | 81 | 78 | 98 | 104 | 104 | 106 | 104 | 95 | 85 | 84 | 106 |
| 2019 | 95 | 85 | 89 | 77 | 91 | 97 | 100 | 103 | 103 | 102 | 85 | 81 | 103 |
| 2020 | 85 | 86 | 73 | 69 | 79 | | | | | | | | |

Monthly & Yearly Peaks




**Attachment 1 for Henderson's Response to Commission Staff 4**

## Energy Taken from Station Two
2013 - Annual Peak Hour

| Year | Month | Date | Peak | Hour | Energy Taken (MW) |
|---|---|---|---|---|---|
| 2013 | January | 22 | 89 | 900 | 81 |
| 2013 | February | 1 | 90 | 800 | 84 |
| 2013 | March | 5 | 85 | 1900 | 81 |
| 2013 | April | 17 | 83 | 1500 | 78 |
| 2013 | May | 29 | 94 | 1700 | 91 |
| 2013 | June | 12 | 104 | 1500 | 96 |
| 2013 | July | 18 | 108 | 1600 | 102 |
| 2013 | August | 29 | 108 | 1600 | 104 |
| 2013 | September | 11 | 105 | 1600 | 101 |
| 2013 | October | 3 | 94 | 1600 | 90 |
| 2013 | November | 27 | 84 | 800 | 82 |
| 2013 | December | 12 | 93 | 800 | 88 |

## Energy Taken from Station Two
2014 - Annual Peak Hour

| Year | Month | Date | Peak | Hour | Energy Taken (MW) |
|---|---|---|---|---|---|
| 2014 | January | 6 | 102 | 1800 | 97 |
| 2014 | February | 11 | 96 | 900 | 89 |
| 2014 | March | 3 | 89 | 1000 | 85 |
| 2014 | April | 16 | 78 | 800 | 75 |
| 2014 | May | 28 | 97 | 1700 | 94 |
| 2014 | June | 18 | 107 | 1500 | 103 |
| 2014 | July | 22 | 106 | 1600 | 97 |
| 2014 | August | 26 | 108 | 1600 | 101 |
| 2014 | September | 4 | 104 | 1700 | 99 |
| 2014 | October | 2 | 93 | 1500 | 89 |
| 2014 | November | 18 | 88 | 1800 | 85 |
| 2014 | December | 2 | 84 | 1800 | 80 |

## Energy Taken from Station Two
2015 - Annual Peak Hour

| Year | Month | Date | Peak | Hour | Energy Taken (MW) |
|---|---|---|---|---|---|
| 2015 | January | 7 | 100 | 1800 | 95 |
| 2015 | February | 19 | 97 | 1900 | 91 |
| 2015 | March | 6 | 88 | 900 | 88 |
| 2015 | April | 9 | 76 | 1400 | 73 |
| 2015 | May | 8 | 90 | 1600 | 84 |
| 2015 | June | 12 | 104 | 1600 | 98 |
| 2015 | July | 29 | 109 | 1600 | 102 |
| 2015 | August | 3 | 106 | 1600 | 99 |
| 2015 | September | 3 | 104 | 1600 | 100 |
| 2015 | October | 7 | 87 | 1600 | 83 |
| 2015 | November | 5 | 76 | 1300 | 73 |
| 2015 | December | 17 | 82 | 1800 | 75 |

## Energy Taken from Station Two
2016 - Annual Peak Hour

| Year | Month | Date | Peak | Hour | Energy Taken (MW) |
|---|---|---|---|---|---|
| 2016 | January | 19 | 94 | 800 | 92 |
| 2016 | February | 10 | 91 | 900 | 89 |
| 2016 | March | 4 | 81 | 900 | 81 |
| 2016 | April | 26 | 85 | 1600 | 82 |
| 2016 | May | 31 | 91 | 1600 | 85 |
| 2016 | June | 16 | 106 | 1500 | 99 |
| 2016 | July | 21 | 107 | 1600 | 99 |
| 2016 | August | 25 | 105 | 1600 | 98 |
| 2016 | September | 7 | 103 | 1500 | 97 |
| 2016 | October | 6 | 91 | 1500 | 87 |
| 2016 | November | 1 | 80 | 1500 | 78 |
| 2016 | December | 19 | 93 | 1000 | 91 |

## Energy Taken from Station Two
2017 - Annual Peak Hour

| Year | Month | Date | Peak | Hour | Energy Taken (MW) |
|---|---|---|---|---|---|
| 2017 | January | 6 | 92 | 1000 | 75 |
| 2017 | February | 9 | 85 | 900 | 84 |
| 2017 | March | 15 | 85 | 800 | 84 |
| 2017 | April | 26 | 83 | 1700 | 79 |
| 2017 | May | 19 | 94 | 1400 | 88 |
| 2017 | June | 14 | 105 | 1600 | 97 |
| 2017 | July | 21 | 110 | 1500 | 102 |
| 2017 | August | 21 | 101 | 1700 | 96 |
| 2017 | September | 21 | 102 | 1600 | 97 |
| 2017 | October | 4 | 88 | 1600 | 85 |
| 2017 | November | 17 | 78 | 900 | 77 |
| 2017 | December | 27 | 83 | 900 | 0 |

## Energy Taken from Station Two
2018 - Annual Peak Hour

| Year | Month | Date | Peak | Hour | Energy Taken (MW) |
|---|---|---|---|---|---|
| 2018 | January | 2 | 900 | 94 | 0 |
| 2018 | February | 2 | 800 | 88 | 86 |
| 2018 | March | 4 | 900 | 81 | 0 |
| 2018 | April | 16 | 78 | 1300 | 75 |
| 2018 | May | 14 | 98 | 1700 | 93 |
| 2018 | June | 18 | 104 | 1500 | 97 |
| 2018 | July | 10 | 104 | 1700 | 0 |
| 2018 | August | 28 | 106 | 1600 | 100 |
| 2018 | September | 5 | 104 | 1600 | 98 |
| 2018 | October | 5 | 95 | 1500 | 92 |
| 2018 | November | 28 | 85 | 800 | 85 |
| 2018 | December | 11 | 84 | 800 | 84 |

# DRAFT

# 2017 LOAD FORECAST

Prepared for:

## HENDERSON MUNICIPAL POWER & LIGHT

August 31, 2017

Prepared By:

GDS Associates, Inc.
ENGINEERS & CONSULTANTS
gdsassociates.com

# Table of Contents


**1 SUMMARY OF LOAD FORECAST** ..... 1

**2 FORECAST ASSUMPTIONS** ..... 4

2.1 Weather ..... 4

2.2 Economy ..... 4

2.3 System Specific Assumption ..... 5

**3 MODEL SPECIFICATION AND METHODOLOGY** ..... 6

**APPENDIX A – MONTHLY FORECAST TABLES AND CHARTS**

# 1 Summary of Load Forecast

GDS Associates, Inc. ("GDS") prepared a Load Forecast for Henderson Municipal Power & Light ("HMPL") in August 2017. GDS prepared annual and monthly projections of total energy requirements (inclusive of distribution line losses) and total demand requirements for 2017 through 2027. This report presents the load forecast, describes the methodology employed by GDS to project energy and peak demand, and describes the major assumptions and data sources used.

Energy requirements are projected to increase at an average compound rate of 0.1% per year from 2017 through 2027. Low energy growth is attributed to no expectation of customer growth, the fact that residential household consumption has declined in recent years throughout the United States due to energy efficiency and conservation efforts, and that we assume no growth of industrial energy sales.[1] Low to even negative growth projections are not uncommon in the industry today.

Summer internal system demands are projected to decline slightly for the next ten years. Summer demands have been declining over the last ten years, resulting in a rising load factor. GDS projects load factor to rise slightly over the forecast horizon, resulting in a peak demand that declines by 1 MW through 2027, reaching 106 MW. Winter peak demands, conversely, are projected to rise at a pace higher than energy requirements growth, increasing by 0.4% per year from 2017 to 2027, to a level of 97 MW. Growth in winter demand is due primarily to continued increases in the market shares of electric heating[2] and electric water heating. Over the last 20 years, winter peak demand has increased at 0.2% per year. as indicated by data from the US Census Bureau.

HMPL has historically been a summer peaking system with summer peaks being approximately 25% higher than winter peaks. The system is projected to remain a summer peaking system throughout the next ten years. However, by 2027 the summer peak demand is expected to only be 10% higher than the winter peak demand.

**Table 1: Summary of Load Forecast**

| Year | Energy Requirements (MWh) | Compound Growth Rate | Summer Peak Demand (MW) | Compound Growth Rate | Summer Load Factor | Winter Peak Demand (MW) | Compound Growth Rate | Winter Load Factor |
|---|---|---|---|---|---|---|---|---|
| 2007 | 690,270 | | 125.0 | | 63.0% | 101.0 | | 78.0% |
| 2012 | 622,254 | -2.1% | 115.0 | -1.7% | 61.8% | 89.0 | -2.5% | 79.8% |
| 2017 | 626,016 | 0.1% | 107.3 | -1.4% | 66.6% | 93.0 | 0.9% | 76.8% |
| 2022 | 627,384 | 0.0% | 106.7 | -0.1% | 67.1% | 95.7 | 0.6% | 74.8% |
| 2027 | 630,441 | 0.1% | 106.4 | -0.1% | 67.6% | 96.8 | 0.2% | 74.4% |

Detailed tables and charts depicting the load forecast are provided in the following pages. Monthly projections of energy and demand are provided in the Appendix.

[1] With a high percentage of industrial energy sales, HMP&L's forecast is particularly sensitive to the assumption of no industrial growth. See Section 2 regarding assumptions for further information.

[2] US Census Bureau

## 2017 LOAD FORECAST
## ANNUAL ENERGY & PEAK DEMAND REQUIREMENTS

| Year | Energy Requirements (MWh) | % Change | Summer Peak Demand (MW) | % Change | Summer Load Factor | Winter Peak Demand (MW) | % Change | Winter Load Factor |
|---|---|---|---|---|---|---|---|---|
| 1997 | 603,213 | | 114.7 | | 60.0% | 89.0 | | 77.4% |
| 1998 | 634,060 | 5.1% | 118.0 | 2.9% | 61.3% | 88.0 | -1.1% | 82.3% |
| 1999 | 660,258 | 4.1% | 123.0 | 4.2% | 61.3% | 92.0 | 4.5% | 81.9% |
| 2000 | 659,001 | -0.2% | 123.0 | 0.0% | 61.2% | 96.0 | 4.3% | 78.4% |
| 2001 | 643,295 | -2.4% | 119.0 | -3.3% | 61.7% | 95.0 | -1.0% | 77.3% |
| 2002 | 673,932 | 4.8% | 124.0 | 4.2% | 62.0% | 93.0 | -2.1% | 82.7% |
| 2003 | 628,572 | -6.7% | 121.0 | -2.4% | 59.3% | 92.0 | -1.1% | 78.0% |
| 2004 | 679,204 | 8.1% | 120.0 | -0.8% | 64.6% | 96.0 | 4.3% | 80.8% |
| 2005 | 687,000 | 1.1% | 124.0 | 3.3% | 63.2% | 98.0 | 2.1% | 80.0% |
| 2006 | 673,114 | -2.0% | 122.0 | -1.6% | 63.0% | 98.0 | 0.0% | 78.4% |
| 2007 | 690,270 | 2.5% | 125.0 | 2.5% | 63.0% | 101.0 | 3.1% | 78.0% |
| 2008 | 658,517 | -4.6% | 119.0 | -4.8% | 63.2% | 100.0 | -1.0% | 75.2% |
| 2009 | 588,663 | -10.6% | 111.0 | -6.7% | 60.5% | 95.0 | -5.0% | 70.7% |
| 2010 | 643,103 | 9.2% | 117.0 | 5.4% | 62.7% | 95.0 | 0.0% | 77.3% |
| 2011 | 622,844 | -3.2% | 113.0 | -3.4% | 62.9% | 94.0 | -1.1% | 75.6% |
| 2012 | 622,254 | -0.1% | 115.0 | 1.8% | 61.8% | 89.0 | -5.3% | 79.8% |
| 2013 | 617,149 | -0.8% | 108.0 | -6.1% | 65.2% | 90.0 | 1.1% | 78.3% |
| 2014 | 639,296 | 3.6% | 108.0 | 0.0% | 67.6% | 102.0 | 13.3% | 71.5% |
| 2015 | 625,083 | -2.2% | 109.0 | 0.9% | 65.5% | 100.0 | -2.0% | 71.4% |
| 2016 | 624,347 | -0.1% | 107.0 | -1.8% | 66.6% | 94.0 | -6.0% | 75.8% |
| 2017* | 622,299 | -0.3% | | | | 93.0 | -1.1% | 76.4% |
| 2017 Norm** | 626,016 | 0.6% | 107.3 | | 66.6% | 93.0 | 0.0% | 76.8% |
| 2018 | 626,383 | 0.1% | 107.3 | 0.1% | 66.6% | 95.0 | 2.2% | 75.2% |
| 2019 | 626,864 | 0.1% | 107.2 | -0.1% | 66.7% | 95.2 | 0.2% | 75.1% |
| 2020 | 626,765 | 0.0% | 107.0 | -0.2% | 66.9% | 95.4 | 0.1% | 75.0% |
| 2021 | 627,012 | 0.0% | 106.8 | -0.1% | 67.0% | 95.5 | 0.2% | 74.9% |
| 2022 | 627,384 | 0.1% | 106.7 | -0.1% | 67.1% | 95.7 | 0.2% | 74.8% |
| 2023 | 627,835 | 0.1% | 106.6 | -0.1% | 67.2% | 95.9 | 0.2% | 74.7% |
| 2024 | 628,348 | 0.1% | 106.5 | -0.1% | 67.3% | 96.1 | 0.2% | 74.6% |
| 2025 | 628,950 | 0.1% | 106.5 | -0.1% | 67.4% | 96.3 | 0.2% | 74.5% |
| 2026 | 629,666 | 0.1% | 106.4 | 0.0% | 67.5% | 96.5 | 0.2% | 74.5% |
| 2027 | 630,441 | 0.1% | 106.4 | 0.0% | 67.6% | 96.8 | 0.2% | 74.4% |

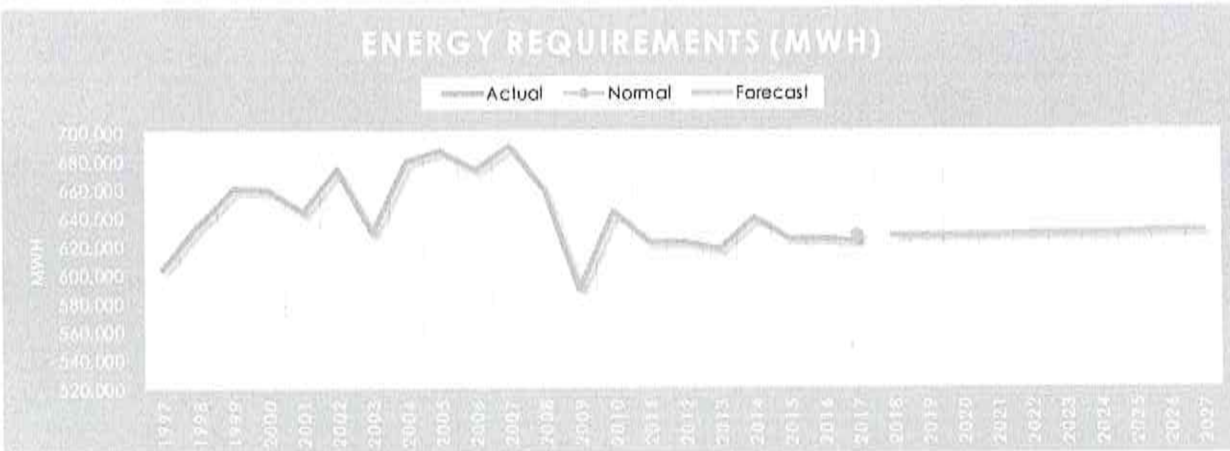
## AVERAGE COMPOUND GROWTH RATES

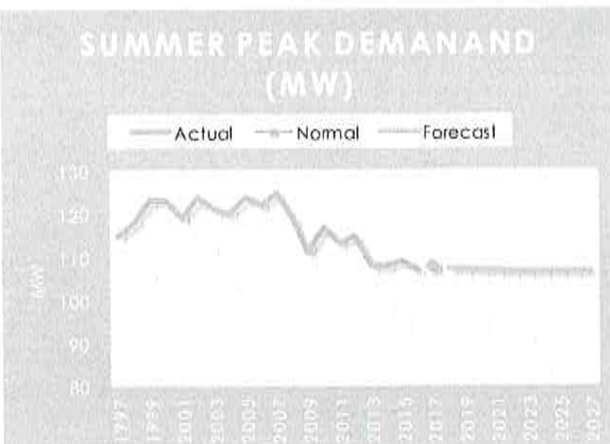
| | | | |
|---|---|---|---|
| 97-02 | 2.2% | 1.6% | 0.9% |
| 02-07 | 0.5% | 0.2% | 1.7% |
| 07-12 | -2.1% | -1.7% | -2.5% |
| 12-17 | 0.1% | -1.4% | 0.9% |
| 17-22 | 0.0% | -0.1% | 0.6% |
| 22-27 | 0.1% | -0.1% | 0.2% |
| 17-27 | 0.1% | -0.1% | 0.4% |

* 2017 represents actual data for January through June and projected data for July through December.

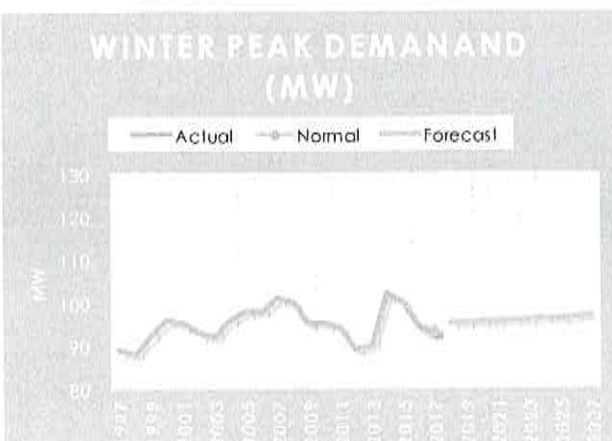
** Represents weather normalized 2017 projections.

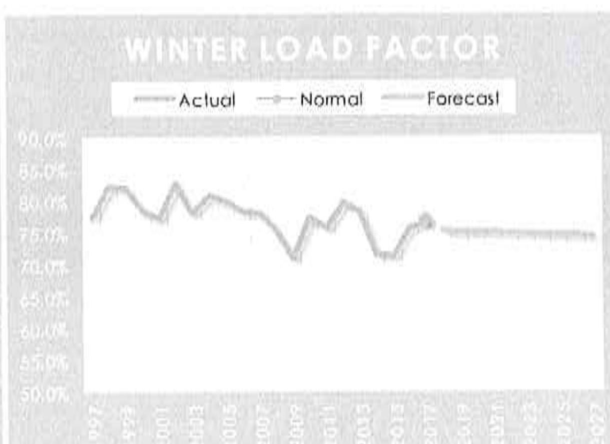
## 2017 LOAD FORECAST
## ANNUAL ENERGY & PEAK DEMAND REQUIREMENTS







# 2 Forecast Assumptions

The forecast is based on a series of assumptions and inputs including assumptions about weather, economic activity, and assumptions specific to the HMPL system including household equipment characteristics, residential price, and industrial activity. This section of the report provides the major assumptions included in the models prepared by GDS to project energy and demand requirements for HMPL.

## 2.1 WEATHER

Henderson is located in northwest Kentucky, situated along the Ohio River. The area is in a humid subtropical climate characterized by hot, humid summers and generally mild to cool winters. Average annual rainfall in the Henderson area, 45 inches, is slightly higher than the US average of 39 inches. Sunny days comprise about 55% of days in a typical year, with high temperatures in July averaging 88°. The January low temperature averages 25°, and the city averages 6" of snowfall per year.

To represent weather conditions in the area, GDS used Heating Degree Days ("HDD") and Cooling Degree Days ("CDD") from Evansville, Indiana. Henderson is located 10 miles south of Evansville. The degree days are computed on a base average temperature of 65°. The forecast assumes normal weather based on twenty-year average degree days ending June 2017.

**Table 2: Weather Data (Evansville, IN)**

| Year | HDD | CDD |
|---|---|---|
| 1997 | 4,901 | 1,119 |
| 1998 | 3,863 | 1,629 |
| 1999 | 4,149 | 1,284 |
| 2000 | 4,710 | 1,289 |
| 2001 | 4,233 | 1,377 |
| 2002 | 4,410 | 1,737 |
| 2003 | 4,529 | 1,143 |
| 2004 | 4,253 | 1,269 |
| 2005 | 4,320 | 1,544 |
| 2006 | 4,044 | 1,342 |
| 2007 | 4,159 | 1,888 |
| 2008 | 4,690 | 1,421 |
| 2009 | 4,413 | 1,281 |
| 2010 | 4,676 | 1,904 |
| 2011 | 4,195 | 1,616 |
| 2012 | 3,666 | 1,845 |
| 2013 | 4,712 | 1,467 |
| 2014 | 4,930 | 1,477 |
| 2015 | 4,067 | 1,579 |
| 2016 | 3,870 | 1,775 |
| Normal | 4,288 | 1,519 |

## 2.2 ECONOMY

Economic projections were obtained from Woods & Poole Economics, Inc ("W&P"). Economic projections are provided by W&P for each county in Kentucky, but not for the Henderson city limits itself. Caution must be used when using county-level economic projections to represent economic activity for a city with defined boundaries. Often, cities are more developed than outlying county territories, meaning household and population growth might be driven more by rural parts of the county rather than the major cities in the county. However, for the HMPL forecast, GDS only used household income, people per household, and retail sales as key economic drivers in the model. These growth rates for these variables are likely to be consistent enough between the county and city that GDS did not adjustment the W&P projections. The following summarizes the economic projections:

- Real household income is projected to grow by 1.5% per year from 2017 through 2027. This is higher than the average growth rate of the prior ten years of 1.2% per year.
- People per household will remain consistent over the forecast horizon, dropping from 2.32 to 2.31 persons per household. This metric has been declining in the last ten to twenty years throughout the country due to generational patterns in marriage and starting families. In Henderson, the average people per household declined from 2.37 to 2.32 from 2007 to 2017.

- Real retail sales in the county grew by an average rate of 0.7% per year from 2007 to 2017. The forecast shows a slight uptick in growth, projecting growth of 0.9% per year for the next ten years.
- Inflation, as measured by the Purchase Consumption Expenditure deflator, is expected to average 1.4% per year over the next ten years.
- Residential price elasticity of demand is assumed to be -0.2%, consistent with studies GDS has performed for distribution cooperative utilities in and around Kentucky.
- Residential household income elasticity is assumed to be 0.1%.
- Residential household size elasticity is assumed to be 0.2%.

## 2.3 SYSTEM SPECIFIC ASSUMPTION

Several assumptions are made specific to the HMPL system specifically.

- The total number of customers served by HMPL has been flat since 2013. The GDS model projects total energy sales, and the model specification implicitly assumes little to no customer growth over the next ten years.
- Nominal residential price of electricity will grow at the rate of inflation.
- Average electric heating and air conditioning efficiencies will track the projections made by the Energy Information Administration ("EIA") in their Annual Energy Outlook. The EIA performs a detailed evaluation of average equipment efficiencies in service throughout the United States and models changes in efficiency due to vintaging of equipment and Federal standards and codes.
    - Average system heating HSPF will increase from 8.58 to 9.39 from 2017 to 2027.
    - Average cooling SEER will increase from 14.37 to 16.31 from 2017 to 2027.
- Air conditioning market share is consistent with end-use saturation data that GDS has collected for areas in and around Henderson. Central AC saturation is assumed to be just over 90% and remain fairly constant for the next ten years.
- Electric heating saturation is based on American Community Survey ("ACS") data collected by the US Census Bureau. The ACS indicates that 40% of homes has electric heat as the primary heating fuel in Henderson in 2010. The percentage increased to 52% by in 2015, according to the same data source.[3] GDS assumes a slower rate of growth in electric heating market share, reaching 53% by 2027.
- GDS assumes that approximately 22% of energy requirements will be sold to residential consumers and 21% to commercial consumers.
- We assume no growth in industrial energy sales into the future. Our forecasting practice is to only include industrial growth for known and measurable changes for existing customers, or new customers that have contracts or have requested service.

[3] The 2015 estimate based on ACS data compares favorably to a 2017 estimate based on data provided by HMPL.

# 3 Model Specification and Methodology

Statistically adjusted end-use ("SAE") models were developed to forecast total system energy and peak demand requirements. SAE models combine the benefits of end-use models and multiple regression based econometric models.

A single model was developed to forecast total system energy sales; however, weighting techniques were used to represent the residential, commercial, and industrial components of total requirements. Factors impacting residential sales were quantified through three indices representing the impacts on heating, cooling, and base load consumption. A retail sales parameter was included to quantify impacts on commercial energy sales, and historical industrial sales were included to measure the impacts of that class on total system sales. The model developed to forecast peak demand was based on the same model specification.

The variables specified in both models are described below. The models are based on 20 years of history and were developed using monthly data.

- Residential Cooling Index – this variable represents the impacts of air conditioning on residential consumption. It incorporates AC market share, AC efficiency, CDD, home size, household size, household income, and price of electricity. The variable is also weighted by the assumed share of total energy expected to be derived from the residential class.

- Residential Heating Index - this variable represents the impacts of electric heating on residential consumption. It incorporates electric heat market share, appliance efficiency, HDD, home size, household size, household income, and price of electricity. The variable is also weighted by the assumed share of total energy expected to be derived from the residential class.

- Residential Base Index – this variable represents the impacts of all other appliances on residential consumption. It incorporates assumed impacts from water heating, refrigeration, washing and drying, dishwashers, TVs, computers and other miscellaneous electric devices.

- Commercial Weighted Retail Sales – this variable represents growth in commercial energy and demand requirements as being driven by changes in retail sales in the area. The variable is simple the retail sales projection from W&P weighted by the assumed share of commercial sales.

- Industrial Index – the industrial index is simply the industrial energy sales expressed on a monthly basis. In the future, the variable is held constant to reflect no growth in industrial sales.

### Table 3: Energy Model Regression Output

| Regression Statistics | |
|---|---|
| Multiple R | 0.9988 |
| R Square | 0.9975 |
| Adjusted R Square | 0.9933 |
| Standard Error | 2,710.3 |
| Mean Absolute % Error (MAPE) | 3.8% |
| Observations | 246 |

ANOVA

| | df | SS | MS | F | Significance F |
|---|---|---|---|---|---|
| Regression | 5 | 711,844,990,669 | 142,368,998,134 | 19,381 | 0 |
| Residual | 241 | 1,770,378,308 | 7,345,968 | | |
| Total | 246 | 713,615,368,977 | | | |

| | Coefficients | Standard Error | t Stat | P-value | Lower 95% | Upper 95% |
|---|---|---|---|---|---|---|
| R_COOL | 25,456.7888 | 982.55 | 25.91 | 1.301E-71 | 23,521.3 | 27,392.3 |
| R_HEAT | 12,267.8951 | 1,119.77 | 10.96 | 6.242E-23 | 10,062.1 | 14,473.7 |
| R_BASE | 9,735.9704 | 1,831.58 | 5.32 | 2.422E-07 | 6,128.0 | 13,343.9 |
| C_RETSALE | 98.8002 | 3.14 | 31.43 | 3.217E-87 | 92.6 | 105.0 |
| IND | 0.8004 | 0.05 | 15.60 | 2.197E-38 | 0.7 | 0.9 |

### Table 4: Demand Model Regression Output

| Regression Statistics | |
|---|---|
| Multiple R | 0.9978 |
| R Square | 0.9955 |
| Adjusted R Square | 0.9913 |
| Standard Error | 6.6 |
| Mean Absolute Percent Error (MAPE) | 5.3% |
| Observations | 246 |

ANOVA

| | df | SS | MS | F | Significance F |
|---|---|---|---|---|---|
| Regression | 5 | 2,370,094 | 474,019 | 10,744 | 5.9405E-280 |
| Residual | 241 | 10,632 | 44 | | |
| Total | 246 | 2,380,726 | | | |

| | Coefficients | Standard Error | t Stat | P-value | Lower 95% | Upper 95% |
|---|---|---|---|---|---|---|
| R_COOL | 47.0067 | 2.41 | 19.52 | 1.542E-51 | 42.3 | 51.7 |
| R_HEAT | 7.7170 | 2.74 | 2.81 | 5.327E-03 | 2.3 | 13.1 |
| R_BASE | 17.3805 | 4.49 | 3.87 | 1.390E-04 | 8.5 | 26.2 |
| C_RETSALE | 0.1843 | 0.01 | 23.93 | 1.337E-65 | 0.2 | 0.2 |
| IND | 0.0016 | 0.00 | 12.38 | 1.448E-27 | 0.0 | 0.0 |

# APPENDIX A
# MONTHLY ENERGY & PEAK DEMAND REQUIREMENTS

## 2017 LOAD FORECAST
## MONTHLY ENERGY & PEAK DEMAND REQUIREMENTS

| Year | Month | Energy Requirements (MWh) | % of Annual | Demand Requirements (MW) | % of Annual Peak |
|---|---|---|---|---|---|
| 2016 | 1 | 54,102 | 8.7% | 94.0 | 87.9% |
| 2016 | 2 | 49,321 | 7.9% | 91.0 | 85.0% |
| 2016 | 3 | 48,876 | 7.8% | 81.0 | 75.7% |
| 2016 | 4 | 47,124 | 7.5% | 85.0 | 79.4% |
| 2016 | 5 | 49,283 | 7.9% | 91.0 | 85.0% |
| 2016 | 6 | 57,962 | 9.3% | 106.0 | 99.1% |
| 2016 | 7 | 57,429 | 9.2% | 107.0 | 100.0% |
| 2016 | 8 | 60,323 | 9.7% | 105.0 | 98.1% |
| 2016 | 9 | 53,426 | 8.6% | 103.0 | 96.3% |
| 2016 | 10 | 49,147 | 7.9% | 91.0 | 85.0% |
| 2016 | 11 | 45,679 | 7.3% | 80.0 | 74.8% |
| 2016 | 12 | 51,675 | 8.3% | 93.0 | 86.9% |
| 2017 | 1 | 52,256 | 8.4% | 92.0 | 85.8% |
| 2017 | 2 | 45,844 | 7.4% | 85.0 | 79.2% |
| 2017 | 3 | 49,549 | 8.0% | 85.0 | 79.2% |
| 2017 | 4 | 46,048 | 7.4% | 83.0 | 77.4% |
| 2017 | 5 | 50,829 | 8.2% | 94.0 | 87.6% |
| 2017 | 6 | 55,428 | 8.9% | 105.0 | 97.9% |
| 2017 | 7 | 59,529 | 9.6% | 107.3 | 100.0% |
| 2017 | 8 | 58,844 | 9.5% | 106.1 | 98.9% |
| 2017 | 9 | 52,336 | 8.4% | 94.3 | 87.9% |
| 2017 | 10 | 49,019 | 7.9% | 86.6 | 80.7% |
| 2017 | 11 | 49,931 | 8.0% | 85.6 | 79.8% |
| 2017 | 12 | 52,685 | 8.5% | 91.3 | 85.1% |
| 2018 | 1 | 52,756 | 8.4% | 95.0 | 88.5% |
| 2018 | 2 | 50,838 | 8.1% | 93.0 | 86.6% |
| 2018 | 3 | 49,901 | 8.0% | 93.4 | 87.0% |
| 2018 | 4 | 48,138 | 7.7% | 86.2 | 80.3% |
| 2018 | 5 | 50,295 | 8.0% | 91.5 | 85.2% |
| 2018 | 6 | 55,653 | 8.9% | 101.8 | 94.8% |
| 2018 | 7 | 58,765 | 9.4% | 107.3 | 100.0% |
| 2018 | 8 | 58,099 | 9.3% | 106.2 | 98.9% |
| 2018 | 9 | 51,774 | 8.3% | 94.6 | 88.1% |
| 2018 | 10 | 48,561 | 7.8% | 87.0 | 81.0% |
| 2018 | 11 | 49,456 | 7.9% | 86.0 | 80.1% |
| 2018 | 12 | 52,147 | 8.3% | 95.1 | 88.6% |

## 2017 LOAD FORECAST
## MONTHLY ENERGY & PEAK DEMAND REQUIREMENTS

| Year | Month | Energy Requirements (MWh) | % of Annual | Demand Requirements (MW) | % of Annual Peak |
|---|---|---|---|---|---|
| 2019 | 1 | 52,813 | 8.4% | 95.2 | 88.8% |
| 2019 | 2 | 50,914 | 8.1% | 93.2 | 87.0% |
| 2019 | 3 | 49,988 | 8.0% | 93.6 | 87.3% |
| 2019 | 4 | 48,239 | 7.7% | 86.4 | 80.6% |
| 2019 | 5 | 50,355 | 8.0% | 91.6 | 85.5% |
| 2019 | 6 | 55,620 | 8.9% | 101.7 | 94.9% |
| 2019 | 7 | 58,683 | 9.4% | 107.2 | 100.0% |
| 2019 | 8 | 58,028 | 9.3% | 106.0 | 98.9% |
| 2019 | 9 | 51,806 | 8.3% | 94.6 | 88.3% |
| 2019 | 10 | 48,657 | 7.8% | 87.2 | 81.3% |
| 2019 | 11 | 49,548 | 7.9% | 86.2 | 80.4% |
| 2019 | 12 | 52,210 | 8.3% | 95.2 | 88.8% |
| 2020 | 1 | 52,823 | 8.4% | 95.4 | 89.1% |
| 2020 | 2 | 50,946 | 8.1% | 93.4 | 87.3% |
| 2020 | 3 | 50,026 | 8.0% | 93.8 | 87.6% |
| 2020 | 4 | 48,290 | 7.7% | 86.6 | 80.9% |
| 2020 | 5 | 50,365 | 8.0% | 91.7 | 85.7% |
| 2020 | 6 | 55,543 | 8.9% | 101.6 | 94.9% |
| 2020 | 7 | 58,557 | 9.3% | 107.0 | 100.0% |
| 2020 | 8 | 57,912 | 9.2% | 105.8 | 98.9% |
| 2020 | 9 | 51,790 | 8.3% | 94.6 | 88.4% |
| 2020 | 10 | 48,700 | 7.8% | 87.3 | 81.6% |
| 2020 | 11 | 49,589 | 7.9% | 86.3 | 80.7% |
| 2020 | 12 | 52,223 | 8.3% | 95.4 | 89.1% |
| 2021 | 1 | 52,861 | 8.4% | 95.5 | 89.4% |
| 2021 | 2 | 51,003 | 8.1% | 93.6 | 87.6% |
| 2021 | 3 | 50,091 | 8.0% | 94.0 | 87.9% |
| 2021 | 4 | 48,367 | 7.7% | 86.7 | 81.2% |
| 2021 | 5 | 50,405 | 8.0% | 91.7 | 85.9% |
| 2021 | 6 | 55,499 | 8.9% | 101.5 | 95.0% |
| 2021 | 7 | 58,467 | 9.3% | 106.8 | 100.0% |
| 2021 | 8 | 57,832 | 9.2% | 105.7 | 98.9% |
| 2021 | 9 | 51,803 | 8.3% | 94.7 | 88.6% |
| 2021 | 10 | 48,769 | 7.8% | 87.4 | 81.9% |
| 2021 | 11 | 49,654 | 7.9% | 86.5 | 80.9% |
| 2021 | 12 | 52,261 | 8.3% | 95.6 | 89.4% |

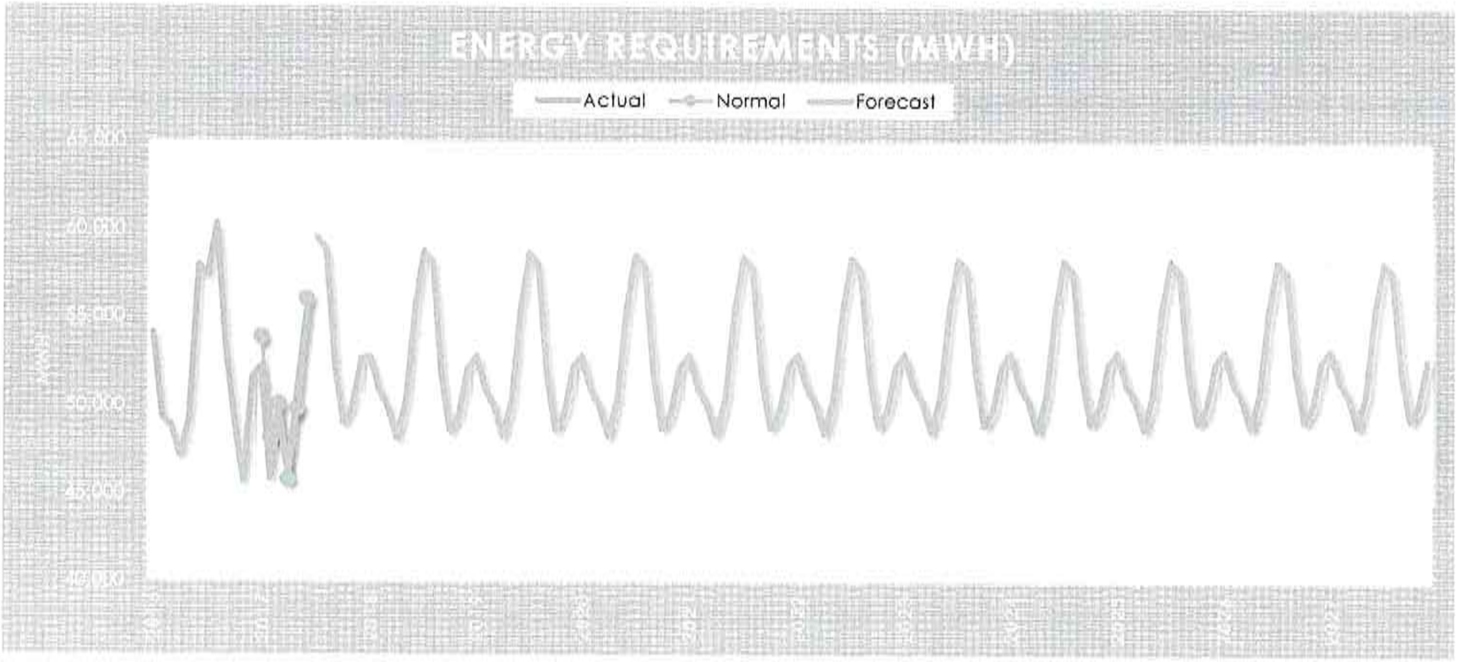
## 2017 LOAD FORECAST
## MONTHLY ENERGY & PEAK DEMAND REQUIREMENTS

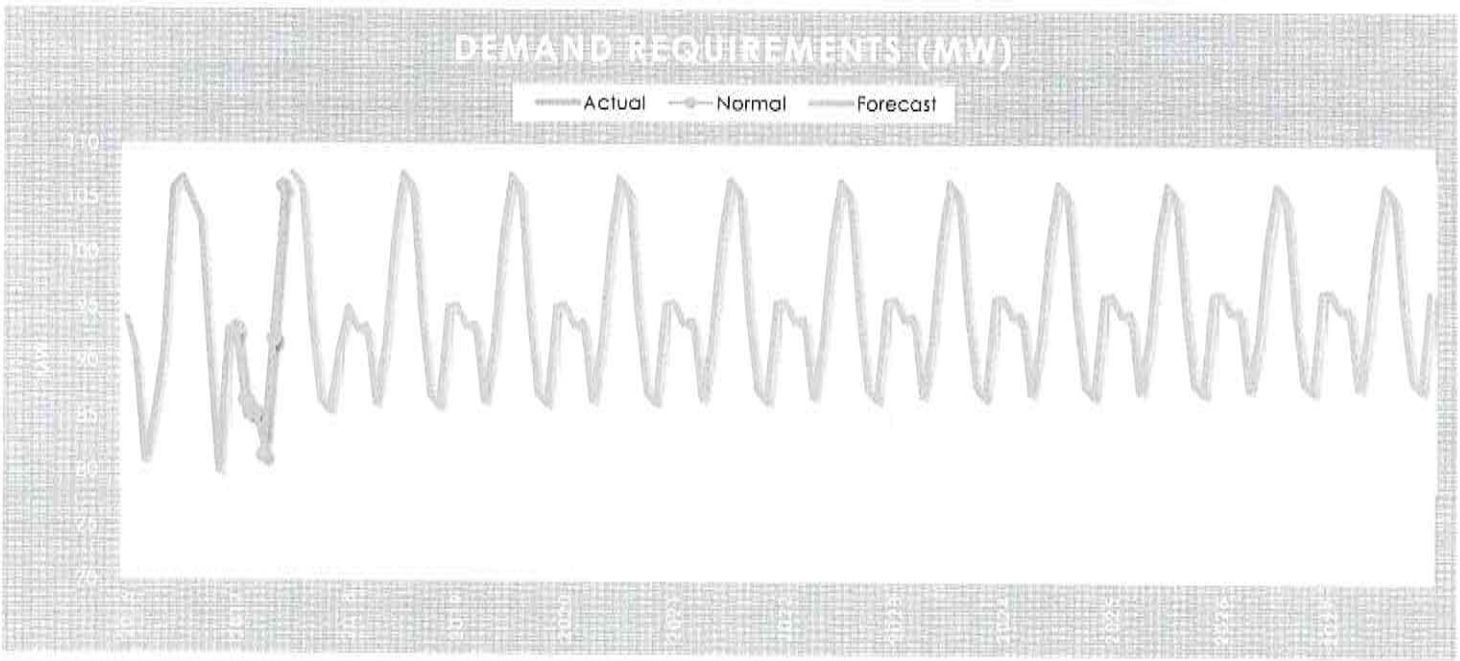
| Year | Month | Energy Requirements (MWh) | % of Annual | Demand Requirements (MW) | % of Annual Peak |
|---|---|---|---|---|---|
| 2022 | 1 | 52,908 | 8.4% | 95.7 | 89.7% |
| 2022 | 2 | 51,066 | 8.1% | 93.8 | 87.9% |
| 2022 | 3 | 50,163 | 8.0% | 94.2 | 88.2% |
| 2022 | 4 | 48,452 | 7.7% | 86.9 | 81.4% |
| 2022 | 5 | 50,455 | 8.0% | 91.8 | 86.1% |
| 2022 | 6 | 55,469 | 8.8% | 101.5 | 95.1% |
| 2022 | 7 | 58,394 | 9.3% | 106.7 | 100.0% |
| 2022 | 8 | 57,768 | 9.2% | 105.6 | 98.9% |
| 2022 | 9 | 51,828 | 8.3% | 94.7 | 88.8% |
| 2022 | 10 | 48,847 | 7.8% | 87.6 | 82.1% |
| 2022 | 11 | 49,727 | 7.9% | 86.7 | 81.2% |
| 2022 | 12 | 52,308 | 8.3% | 95.7 | 89.7% |
| 2023 | 1 | 52,959 | 8.4% | 95.9 | 90.0% |
| 2023 | 2 | 51,132 | 8.1% | 94.0 | 88.2% |
| 2023 | 3 | 50,239 | 8.0% | 94.4 | 88.5% |
| 2023 | 4 | 48,540 | 7.7% | 87.1 | 81.7% |
| 2023 | 5 | 50,511 | 8.0% | 92.0 | 86.3% |
| 2023 | 6 | 55,448 | 8.8% | 101.4 | 95.1% |
| 2023 | 7 | 58,333 | 9.3% | 106.6 | 100.0% |
| 2023 | 8 | 57,715 | 9.2% | 105.5 | 99.0% |
| 2023 | 9 | 51,860 | 8.3% | 94.8 | 88.9% |
| 2023 | 10 | 48,929 | 7.8% | 87.8 | 82.3% |
| 2023 | 11 | 49,805 | 7.9% | 86.9 | 81.5% |
| 2023 | 12 | 52,363 | 8.3% | 95.9 | 90.0% |
| 2024 | 1 | 53,013 | 8.4% | 96.1 | 90.2% |
| 2024 | 2 | 51,201 | 8.1% | 94.2 | 88.4% |
| 2024 | 3 | 50,318 | 8.0% | 94.6 | 88.8% |
| 2024 | 4 | 48,630 | 7.7% | 87.3 | 81.9% |
| 2024 | 5 | 50,570 | 8.0% | 92.1 | 86.4% |
| 2024 | 6 | 55,436 | 8.8% | 101.4 | 95.2% |
| 2024 | 7 | 58,282 | 9.3% | 106.5 | 100.0% |
| 2024 | 8 | 57,673 | 9.2% | 105.4 | 99.0% |
| 2024 | 9 | 51,898 | 8.3% | 94.9 | 89.0% |
| 2024 | 10 | 49,016 | 7.8% | 88.0 | 82.6% |
| 2024 | 11 | 49,888 | 7.9% | 87.0 | 81.7% |
| 2024 | 12 | 52,423 | 8.3% | 96.1 | 90.2% |

# 2017 LOAD FORECAST
## MONTHLY ENERGY & PEAK DEMAND REQUIREMENTS

| Year | Month | Energy Requirements (MWh) | % of Annual | Demand Requirements (MW) | % of Annual Peak |
|---|---|---|---|---|---|
| 2025 | 1 | 53,073 | 8.4% | 96.3 | 90.5% |
| 2025 | 2 | 51,275 | 8.2% | 94.4 | 88.7% |
| 2025 | 3 | 50,402 | 8.0% | 94.8 | 89.0% |
| 2025 | 4 | 48,725 | 7.7% | 87.5 | 82.2% |
| 2025 | 5 | 50,636 | 8.1% | 92.2 | 86.6% |
| 2025 | 6 | 55,433 | 8.8% | 101.4 | 95.3% |
| 2025 | 7 | 58,243 | 9.3% | 106.5 | 100.0% |
| 2025 | 8 | 57,642 | 9.2% | 105.4 | 99.0% |
| 2025 | 9 | 51,943 | 8.3% | 94.9 | 89.2% |
| 2025 | 10 | 49,109 | 7.8% | 88.2 | 82.8% |
| 2025 | 11 | 49,977 | 7.9% | 87.3 | 82.0% |
| 2025 | 12 | 52,490 | 8.3% | 96.4 | 90.5% |
| 2026 | 1 | 53,143 | 8.4% | 96.5 | 90.7% |
| 2026 | 2 | 51,358 | 8.2% | 94.6 | 88.9% |
| 2026 | 3 | 50,496 | 8.0% | 95.0 | 89.3% |
| 2026 | 4 | 48,828 | 7.8% | 87.7 | 82.4% |
| 2026 | 5 | 50,712 | 8.1% | 92.4 | 86.8% |
| 2026 | 6 | 55,442 | 8.8% | 101.4 | 95.3% |
| 2026 | 7 | 58,217 | 9.2% | 106.4 | 100.0% |
| 2026 | 8 | 57,624 | 9.2% | 105.3 | 99.0% |
| 2026 | 9 | 51,999 | 8.3% | 95.0 | 89.3% |
| 2026 | 10 | 49,209 | 7.8% | 88.4 | 83.0% |
| 2026 | 11 | 50,073 | 8.0% | 87.5 | 82.2% |
| 2026 | 12 | 52,565 | 8.3% | 96.6 | 90.8% |
| 2027 | 1 | 53,219 | 8.4% | 96.8 | 91.0% |
| 2027 | 2 | 51,445 | 8.2% | 94.9 | 89.2% |
| 2027 | 3 | 50,593 | 8.0% | 95.2 | 89.5% |
| 2027 | 4 | 48,935 | 7.8% | 87.9 | 82.6% |
| 2027 | 5 | 50,792 | 8.1% | 92.5 | 87.0% |
| 2027 | 6 | 55,458 | 8.8% | 101.5 | 95.4% |
| 2027 | 7 | 58,199 | 9.2% | 106.4 | 100.0% |
| 2027 | 8 | 57,614 | 9.1% | 105.3 | 99.0% |
| 2027 | 9 | 52,059 | 8.3% | 95.2 | 89.5% |
| 2027 | 10 | 49,313 | 7.8% | 88.6 | 83.2% |
| 2027 | 11 | 50,172 | 8.0% | 87.7 | 82.4% |
| 2027 | 12 | 52,643 | 8.4% | 96.6 | 90.8% |

## 2017 LOAD FORECAST
## MONTHLY ENERGY & PEAK DEMAND REQUIREMENTS



**Item 5) Refer to the Bickett Testimony, page 16. Confirm that BREC retained the MISO revenues because Henderson refused to accept receipt of those revenues. If this cannot be confirmed, provide an explanation.**

**Response)** This request confuses two distinct revenue streams. The revenue referenced on page 16 of the Bickett Testimony is that revenue Big Rivers received as a result of its having registered the City's Station Two as an asset in MISO. This revenue would include make-whole payments, payments for system reserves, ancillary services, reactive power, and any other payments MISO made to Big Rivers in connection with Station Two generation assets. Big Rivers never offered Henderson a share of this type of revenue, even though Henderson was the owner of the asset.

The revenue referenced on page 16 of the Bickett testimony is separate and distinct from that revenue associated with the sale of energy which was unprofitable and unwanted by either party and which was the issue before the Commission in Case No. 2016-278. The Commission's Order in that case was based in part upon Big Rivers' representation that it intended to sell the unprofitable energy into the market on Henderson's behalf, recover from Henderson the variable production costs, and remit to Henderson the sales revenue. Henderson rejected revenue checks received from Big Rivers during the pendency of the action because to do otherwise would have been to acquiesce to Big Rivers' position on the very issue before the Commission.

Since the Commission entered its Order on January 5, 2018, Big Rivers has taken the position that Henderson waived its right to this revenue when it accepted $6.25 million from Big Rivers in December 2017 to resolve a wholly unrelated dispute concerning profitable energy which was wanted by both parties and which was at issue in the Henderson Circuit Court, Civil Action No. 09-CI-00693. If Henderson were to accept responsibility for the variable costs of producing unwanted energy, then Henderson is entitled to the revenue associated with the sale of that energy. According to Big Rivers' calculations, attached to the Moll Testimony as Exhibit Moll-2, Henderson would pay variable costs of unwanted energy and reimburse Big Rivers for purported coal and lime shortfalls. Big Rivers in turn would remit to Henderson revenue in the sum of $1,233,583.77. Additionally, Henderson would have to write off $3,500,219 in coal and lime inventory currently reflected as an asset on Henderson's books.

Despite the representations Big Rivers made to the Commission in Case No. 2016-278, Big Rivers reversed its position and now claims that Henderson is responsible for the variable costs of producing unwanted energy, but is not entitled to the associated revenue unless Henderson makes other concessions, such as accepting responsibility for unlimited decommissioning costs. In view of this dispute, Henderson has filed an action seeking a declaratory order from the Henderson Circuit Court interpreting the Settlement Agreement that resolved Civil Action 09-CI-00693 and confirming the distinction between the wanted energy which was at issue in Civil Action No.09-CI-00693 and the unwanted energy which was at issue in Case No. 2016-278, then pending before the Commission. A copy of Henderson's Petition for Declaratory Relief filed on July 29, 2020, is attached to this response.

**Witness)** **Brad Bickett**

COMMONWEALTH OF KENTUCKY
HENDERSON CIRCUIT COURT
CIVIL ACTION NO. 20-CI-_______

*Electronically Filed*

CITY OF HENDERSON, KENTUCKY, and
CITY OF HENDERSON UTILITY COMMISSION,
d/b/a HENDERSON MUNICIPAL POWER & LIGHT — PLAINTIFFS

v.

BIG RIVERS ELECTRIC CORP. — DEFENDANT

Serve: Amanda Jackson
Registered Agent
Big Rivers Electric Corp.
201 Third Street
Henderson, Kentucky 42420

Robert W. Berry
President & CEO
Big Rivers Electric Corp.
201 Third Street
Henderson, Kentucky 42420

## PETITION FOR DECLARATORY RELIEF

Plaintiffs, City of Henderson, Kentucky, and City of Henderson Utility Commission, d/b/a Henderson Municipal Power & Light (jointly "Henderson"), by and through counsel, and pursuant to KRS 418.040 and Kentucky Civil Rule 57, state as follows for their cause of action seeking declaratory relief and enforcement against Defendant Big Rivers Electric Corp. ("Big Rivers"):

### THE PARTIES

1. The City of Henderson, Kentucky, is a Kentucky city of the Home Rule class, with all of the authority and powers specified in and enumerated by the Kentucky Constitution, and state statutes enacted by the Kentucky General Assembly, said authority and powers including but





**Attachment 1 for Henderson's Response to Commission Staff 5**

not being limited to the capacity to enter into legal contracts, and to sue and be sued in its own name.

2. The Henderson Utility Commission, d/b/a Henderson Municipal Power & Light, is a utility commission established by Ordinance of the City of Henderson, Kentucky, pursuant to KRS 96.530 et. seq., and is a public body politic and corporate, with perpetual succession, which has absolute control of the municipally owned electric system of the City of Henderson, Kentucky, which body may contract and be contracted with, sue and be sued, in and by its corporate name. The Henderson Utility Commission, d/b/a Henderson Municipal Power & Light, is headquartered at 100 Fifth Street, Henderson, Kentucky, 42420.

3. Big Rivers Electric Corporation ("Big Rivers") is an electric generation and transmission cooperative corporation headquartered at 201 Third Street, P.O. Box 24, Henderson, Kentucky, 42419-0024, organized pursuant to KRS Chapter 279, and having the capacity to contract, to sue, and to be sued in its own name.

**JURISDICTION & VENUE**

4. Jurisdiction in this Court is proper pursuant to KRS 418.040, et. seq., and KRS Chapter 23A.

5. Venue in this Court is proper pursuant to KRS 452.450, as Big Rivers is situated in Henderson County, Kentucky, and because the contract forming the subject matter of this action was made and is to be performed in Henderson County, Kentucky.

**FACTUAL BACKGROUND AND STATEMENT OF CLAIM**

6. In 1970, Henderson and Big Rivers entered into a series of contracts providing for the construction and operation of a 312 MW generating plant and the allocation of capacity and energy, along with associated costs. The now-retired plant consists of two generating units known collectively as Station Two.

7. In 2009, a dispute arose concerning which party was entitled to take and sell profitable energy which exceeded the amount Henderson needed to serve its inhabitants but which fell within the amount of generating capacity Henderson had reserved and paid for under the terms of the parties' Power Sales Contract, as amended.

8. With the parties unable to resolve their dispute, Big Rivers filed an action in the Henderson Circuit Court, Civil Action No. 09-CI-693, and successfully petitioned the Court to refer the dispute to arbitration.

9. An arbitration panel ultimately concluded that the disputed energy both parties wanted to take and sell belonged to Henderson and that Henderson was entitled to take and schedule its energy for sale, subject to Big Rivers' first right to match any third-party offer Henderson received.

10. Big Rivers nonetheless continued to deny Henderson access to the disputed energy and refused to approve the scheduling protocol Henderson proposed. Because Henderson was precluded from taking and scheduling its energy, Big Rivers was able to continue taking energy which belonged to Henderson and which Henderson otherwise would have called for and sold. Big Rivers thus continued to take Henderson's energy at nominal cost and sell the energy at a substantial profit while Henderson absorbed the cost of the capacity used to generate the energy.





Filed 20-CI-00413 07/29/2020 Herbert McKee, Jr. Henderson Circuit Clerk

11. On February 12, 2016, as each party continued to contest the other's right to access and sell the disputed energy on what was then a robust power market, Henderson sought damages against Big Rivers for lost revenue, reimbursement of capacity costs, and other costs.

12. Henderson filed its Petition for an Award of Damages in the Henderson Circuit Court, Civil Action No. 09-CI-693, which was the same action in which Big Rivers had sought a determination as to which party was entitled to take and sell the profitable energy both parties wanted (a copy of the Petition is attached hereto and marked **Exhibit A**).

13. The profitable energy both parties wanted was the only energy in dispute in Civil Action No.09-CI-693.

14. As the parties litigated their rights and obligations with respect to the disputed energy both parties wanted, market forces created a downturn in energy prices and created a type of energy never referenced in the Power Sales Contract, as amended, or in Civil Action No. 09-CI-693: unprofitable energy which was unwanted by either party to the contracts.

15. On May 25, 2016, Big Rivers notified Henderson that Big Rivers would cease to take and sell Henderson's surplus energy unless that energy happened to be profitable (See correspondence attached hereto and marked **Exhibit B**). Rather, Big Rivers would implement a new practice in which Big Rivers would sell the unprofitable and unwanted energy into the market on Henderson's behalf and assign both variable production costs and any revenue associated with the sale of that energy to Henderson's account.

16. The practice change announced in the May 25, 2016, notice gave rise to a new and distinct dispute concerning responsibility for costs associated with this new and distinct category of unwanted energy. On July 29, 2016, Big Rivers filed an application with the Kentucky Public Service Commission ("Commission") asking the Commission to declare Big Rivers not

responsible for the variable costs of producing unwanted energy and to assign those costs to Henderson.

17. In accordance with the representation made to Henderson in the May 25, 2016, notice, Big Rivers represented to the Commission throughout the proceeding that Big Rivers intended to sell the unwanted energy on Henderson's behalf, assign the variable production costs to Henderson, and pass the sales revenue through to Henderson.

18. On December 15, 2017, with the Commission's ruling on unwanted energy still pending, the parties resolved Henderson's claim for damages associated with the wanted energy at issue in the Henderson Circuit Court, Civil Action No. 09-CI-693 (A copy of the Settlement Agreement & Release ("Settlement Agreement") resolving Civil Action No. 09-CI-693 is attached hereto as **Exhibit C**).

19. The Settlement Agreement is the product of extensive negotiations in which the parties acknowledged both verbally and in writing that the agreement resolved only the claim then pending before the Henderson Circuit Court in Civil Action No. 09-CI-693, which was Henderson's claim for damages associated with the profitable energy which both parties wanted and which had been generated since Big Rivers' 2009 filing. Indeed, the wanted energy is the only energy that could have been at issue in a claim for damages, as there could not possibly be any damages associated with unprofitable and unwanted energy that could only be sold at a loss.

20. Shortly after the execution of the Settlement Agreement, the parties filed an Agreed Order with the Henderson Circuit Court dismissing Civil Action No. 09-CI-693 as settled. Big Rivers did not withdraw its application pending before the Commission and did not take any other steps to notify the Commission that any part of the parties' dispute over unwanted energy had been resolved.

20. On January 5, 2018, the Commission entered an Order finding Big Rivers not responsible for the variable costs of producing unwanted energy (Order attached hereto and marked **Exhibit D**). Subsequent to the entry of the Commission's Order, Big Rivers began to take the position that Henderson owed Big Rivers for the variable costs of producing unwanted energy, but that Henderson had waived its right to receive the associated revenue as part of the agreement to settle the damages claim. For example, in a letter from Big Rivers dated February 16, 2018, (attached hereto and marked **Exhibit E**), Big Rivers demands that Henderson pay the variable costs of producing unwanted energy, but expresses an intent to retain the revenue received from the sale of that energy. This position is contrary to the position Big Rivers took before the Commission and contradicts the intent of the parties to the Settlement Agreement.

21. The Settlement Agreement unambiguously resolves only the damages claim then pending before the Henderson Circuit Court in Civil Action No. 09-CI-693 and reflects the mutual understanding of the parties concerning the limited scope of the agreement. In the alternative and in the event the Court is to resort to extrinsic evidence to determine the intent of the parties, please see the following electronic mail communications, attached hereto and marked collectively as **Exhibit F**: 1) from Big Rivers' counsel Jim Miller to Henderson counsel Randall Redding dated November 10, 2017, stating "Big Rivers' position is that nothing in this settlement agreement affects or has anything to do with the PSC case."; 2) from Henderson counsel Randall Redding to Big Rivers counsel Jim Miller dated November 8, 2017, clarifying the nature of the claims to be released in the Settlement Agreement, i.e. that energy which Henderson would have called for and sold; and 3) from Big Rivers' counsel Theresa Canaday to Henderson counsel Randall Redding, et al., dated January 2, 2018, acknowledging that "the parties have resolved the Big Rivers v. City

of Henderson, et al. matter (Case No. 09-CI-000693) by way of a settlement that anticipates dismissal of the pending lawsuit following payment of specified funds."

22. Henderson has appealed the Commission's Order and has not accepted responsibility for the variable costs of producing unwanted energy generated between June 1, 2016 (the date Big Rivers adopted its new practice) and January 4, 2018 (the date of the settlement payment). However, in the event Henderson were to accept such responsibility, Henderson clearly would be entitled to receive all revenue Big Rivers received for the sale of unwanted energy generated during that time period as an offset against costs.

23. If the Court were to accept Big Rivers' interpretation of the Settlement Agreement, Henderson would be forced to sustain the losses associated with the generation of unwanted energy between June 1, 2016, and January 4, 2018, without the benefit of the corresponding revenue. Additionally, Henderson would be forced to write off some $3.5 million more in coal and lime which belonged to Henderson and which Big Rivers arbitrarily and without Henderson's knowledge or consent used to generate unwanted energy.

24. Big Rivers' position is inequitable, unjust, and contrary to the intent of the parties when they executed the Settlement Agreement resolving the Henderson Circuit Court damages claim.

25. Henderson seeks a declaratory order confirming that the Settlement Agreement is not ambiguous and that the terms agreed to therein pertain solely to the dispute concerning profitable surplus energy both parties wanted to take and sell, and is unrelated to the parties' dispute concerning unprofitable energy that was unwanted by either party.

## ACTUAL CONTROVERSY

26. A dispute has arisen between the parties concerning the interpretation of the Settlement Agreement and the nature of the resolved dispute. On July 31, 2019, Big Rivers filed an application asking the Commission to resolve the numerous disputes remaining between the parties as a result of the closure of Station Two. Big Rivers' calculations of the amounts due between the parties are based in part upon Big Rivers' position that no further revenue is due to Henderson. To the extent the Settlement Agreement requires interpretation, the Henderson Circuit Court – not the Commission – has jurisdiction to do so.

27. Pursuant to KRS 418.040, this Court possesses authority to declare the rights of the parties where there exists an actual controversy. Specifically, under KRS 418.045, any person interested under a contract is entitled to a determination of his rights or duties arising under the instrument, provided there is an actual controversy.

28. Henderson is entitled to a declaration that its interpretation of the Settlement Agreement is correct and that the terms apply solely to the Henderson Circuit Court claim for damages associated with sales of disputed energy both parties wanted and not to any claim related to the generation of unwanted energy.

WHEREFORE, Henderson respectfully requests that the Court advance this case on its calendar and docket for early hearing and decision on motion as provided in KRS 418.050 and CR 57, enter a Declaratory Judgment confirming Henderson's interpretation of the Settlement Agreement.

Respectfully submitted,

**KING, DEEP & BRANAMAN**

/s/H. Randall Redding
H. Randall Redding
Sharon W. Farmer
127 North Main Street
P.O. Box 43
Henderson, Kentucky 42419-0043
Telephone: (270) 827-1852
rredding@kdblaw.com
sfarmer@kdblaw.com
*Attorneys for Henderson Utility Commission, d/b/a Henderson Municipal Power & Light*

/s/Dawn Kelsey
Dawn Kelsey
City Attorney
City of Henderson
222 First Street
Henderson, Kentucky 42420
*Attorney for City of Henderson*

**Item 6) Refer to the Bickett Testimony, page 17, lines 3-10, regarding the contingency reserve necessary to satisfy the North American electric Reliability Corporation (NERC) balancing authority requirements.**

**a. State whether it would have been necessary for Henderson to maintain a reserve margin to satisfy the NERC balancing authority requirements if Henderson had operated Station Two, and if so, describe the reserve margin it would have needed to maintain and explain why it would have needed to do so.**

**b. Confirm that BREC, by satisfying the contingency reserve requirement based on its largest generating unit, also satisfied any reserve requirement that applied to Station Two, and explain each basis for Henderson's response.**

**Response)** a. No. The NERC Balancing Authority requirements do not apply to the NERC function of Generator Operator and would not have applied to Henderson unless Henderson were registered with NERC as a Balancing Authority.

b. This statement is not accurate. The contingency reserve requirement applies only to an entity which is registered as a Balancing Authority in NERC. The NERC Glossary of Terms, updated June 2, 2020, defines "Contingency Reserve" as follows:

> The provision of capacity that may be deployed by the Balancing Authority to respond to a Balancing Contingency Event and other contingency requirements (such as Energy Emergency Alerts as specified in the associated EOP standard),. A Balancing Authority may include in its restoration of Contingency Reserve readiness to reduce Firm Demand and include it if, and only if, the Balancing Authority:
>
> - is experiencing a Reliability Coordinator declared Energy Emergency Alert level, and is utilizing its Contingency Reserve to mitigate an operating emergency in accordance with its emergency Operating Plan.

- is utilizing its Contingency Reserve to mitigate an operating emergency in accordance with its emergency Operating Plan.

**Witness)** **Brad Bickett**

**Item 7)** **Refer to the Bickett Testimony, Exhibit Bickett-4, page 42. Confirm that NERC uses a 15 percent reserve margin for planning purposes for the SERC Reliability Corporation SERC-C assessment area. If this cannot be confirmed, provide an explanation.**

**Response)** Confirmed.

**Witness)** **Brad Bickett**

**Item 8) Refer to the Direct Testimony of Seth W. Brown (Brown Testimony), pages 5-6, regarding the MISO Open Access Transmission, Energy and Operating Reserves Tariff (MISO Tariff), Schedule 17.**

**a. Provide a copy of the MISO Tariff, Schedule 17.**

**b. Provide a copy of Contract No. 510, Agreement for Transmission and Transformation Capacity dated April 11, 1975.**

**c. Provide a copy of Contract No. 511, Letter Agreement for Scheduling Southeastern Power Administration energy.**

**d. Confirm that Henderson is not objecting to the MISO Tariff, Schedule 17 fees of $272,801.97 that BREC is seeking recovery from Henderson.**

**e. On page 6, lines 20-21, there is a reference indicating that Station Two and Henderson's load were registered in the MISO Network and Commercial Model. Explain who registered Station Two and Henderson's load in the MISO Network and Commercial Model and whether Henderson knew of and agreed to this registration.**

**Response)** a. See attached.

b. See attached.

c. See attached.

d. Henderson is objecting to the assessment of the Schedule 17 fees. Henderson owned the generation and associated transmission facilities needed to supply its load. Big Rivers' integration into MISO did not affect Henderson's independent ability to supply its load just as it had done prior to the integration. Henderson did not require or benefit from any of the services offered under Schedule 17. Therefore, those costs are not recoverable from Henderson.

e. Big Rivers advised Henderson in a letter dated September 22, 2010, that Big Rivers had submitted Commercial Model data to MISO and had submitted two required certifications regarding the registration of the Station Two generation asset and the City of Henderson load. Big Rivers confirmed in an electronic mail communication dated September 27, 2010, that Big Rivers had submitted to MISO registration forms for the Station Two units and had registered Henderson's load as part of Big Rivers' load. Both communications were made after the conclusion of the Commission hearing on Big Rivers' application to transfer functional control of its transmission system to MISO. Henderson did not know Big Rivers had registered the Station Two generation or load prior to receiving the letter dated September 22, 2010. Henderson did not consent to the joint registration and did not authorize Big Rivers to act as Henderson's market participant. In fact, Henderson advised Big Rivers on numerous occasions that Henderson intended to register its Station Two capacity and energy separately from Big Rivers and to arrange for its own market participant. The letter dated September 22, 2010, and the email communication dated September 27, 2010, are attached to this response. Both communications, as well as other correspondence related to this issue, are also attached to Henderson's response to Item No. 1.

The certificates which are referenced in the correspondence and which Big Rivers filed with MISO as a representation of its authority to register Station Two were produced as confidential documents subject to an Agreed Protective Order in the Henderson Circuit Court, Civil Action No. 09-CI-00693. Henderson believes the certificates contain information relevant to this proceeding, e.g. documentation that Big Rivers wrongfully represented to MISO that Big Rivers possessed the authority to register the Station Two capacity in MISO. Henderson therefore urges the Commission to order that Big Rivers produce them in this proceeding.

**Witness)** **Seth W. Brown** Items 8(a)-8(d)

**Brad Bickett** Item 8(e)

# SCHEDULE 17

## Energy and Operating Reserve Markets Support Administrative Service Cost Recovery Adder

### I. GENERAL

Energy and Operating Reserve Markets Support Administrative Service (the "Service") is provided by the Transmission Provider to all Market Participants that participate in Transactions using the Transmission System or Energy and Operating Reserve Markets consistent with the terms of this Tariff or applicable Market Participant Agreement in a form provided for in this Tariff. A Market Participant acting as a Grandfathered Agreements ("GFA") Responsible Entity will be assessed Schedule 17 charges for associated injection and withdrawal schedules submitted by the Market Participant in association with service taken pursuant to Option A, Option B, Option C or Carve-Out GFA Tariff provisions as ordered by the Commission.

This Energy and Operating Reserve Markets Support Administrative Service Cost Recovery Adder provides for the recovery of all costs incurred by the Transmission Provider in providing the Service, inclusive of all costs resulting from the assignment or allocation of costs to the Service.1 The Transmission Provider's costs incurred in providing the Service include, but are not limited to, costs associated with: 1) market modeling and scheduling functions; 2) market bidding support; 3) locational marginal pricing support; 4) market settlements and billing; 5) market monitoring functions; and, 6) simultaneous co-optimization for the scheduling and enabling of the least-cost, security-constrained commitment and dispatch of Generation Resources to serve Load and provide Operating Reserves in the MISO Balancing Authority Areas while also establishing a spot energy market.

**Attachment 1 for Henderson's Response to Commission Staff 8(a)**

## II. ENERGY MARKET SUPPORT ADMINISTRATIVE SERVICE COST RECOVERY ADDER

### A. Billing Determinants

The billing determinants for the Energy and Operating Reserve Markets Support Administrative Service Cost Recovery Adder shall be: 1) all Actual Energy Injections into the Transmission System by all Market Participants, less the number of MWh derived pursuant to Schedule 17-B Section II.B.1 and Schedule 17-C Section II.B.1, including deliveries to the Transmission System from generation located both within the Transmission System and outside of the Transmission System, 2) all Actual Energy Withdrawals from the Transmission System by all Market Participants, less the number of MWh derived pursuant to Schedule 17-B Section II.B.2 and Schedule 17-C Section II.B.2, including MWh delivered to loads located both within the Transmission System and outside of the Transmission System including all out and through transactions using the Transmission System; and, 3) all Bids or Offers for Energy that settle in the Day-Ahead Energy and Operating Reserve Market, but do not actually inject MWh into or extract MWh from the Transmission System in the Real-Time Energy and Operating Reserve Market less the number of MWh derived pursuant to Schedule 17-B Section II.B.3 and Schedule 17-C Section II.B.3.

### B. Determination of the Costs To Be Recovered

The costs to be recovered under this Schedule 17 shall include any direct and indirect capital costs, direct and indirect operating expenses and all other costs associated with administering the Service (collectively the "Schedule 17 Costs"). For capital costs, the Transmission Provider shall not recover a rate of return on equity, but instead will recover its actual costs of financing any such capital costs associated with the Service. The indirect capital and indirect operating costs will include an allocable portion of infrastructure, resources, personnel and overheads. Non-allocated operating expenses shall be the direct operating expenses incurred by the Transmission Provider in providing the Service under this Schedule 17. The formula set forth in Section III of this Schedule 17 shall be used to calculate the monthly charges.

**C. <u>Payments Applicable to Withdrawing Entities</u>**

In the event that an owner of transmission facilities withdraws its transmission facilities ("Withdrawing Entity") from the operational control of the Transmission Provider, the Withdrawing Entity shall pay its share of all Schedule 17-related financial obligations incurred and payments applicable to time periods prior to the effective date of such withdrawal (the "Schedule 17 Withdrawal Obligation") as required by Article Five, Section II(B) of the ISO Agreement. The Withdrawing Entity's total responsibility for the Schedule 17 Withdrawal Obligation shall be based on the outcome of a negotiated or contested settlement accepted by the Commission.

**D. <u>Credit for Schedule 17 Withdrawal Obligations</u>**

In determining the costs to be recovered under Schedule 17 a monthly credit shall be applied to the total monthly costs to be recovered to reflect Schedule 17 Withdrawal Obligation payments received from Withdrawing Entities. The variable EMS-CREDIT in the rate formula in Part III will be net of any payments made once per year to E.ON U.S. or its successor(s) as compensation for its share of the actual revenue derived from certain transactions excluded from the computation of the Withdrawal Obligation in Docket No. ER06-1308, *et al.* Such compensation is described more fully in the Recalculation Agreement, FERC Electric Tariff, Rate Schedule No. 12.

The effective date for the monthly credit associated with Schedule 17-B under this Schedule 17 Section II.D shall be June 1, 2011. The termination date shall be May 31, 2026. The monthly amount of the credit shall the unamortized balance of the Withdrawal Obligation under Schedule 17-B as of May 31, 2011, divided by the number of months between June 1, 2011 and May 31, 2026.

The effective date for the monthly credit associated with Schedule 17-C under this Schedule 17 Section II.D shall be January 1, 2012. The termination date shall be December 31, 2026. The monthly amount of the credit shall be the unamortized balance of the Withdrawal Obligation under Schedule 17-C as of December 31, 2011, divided by the number of months between January 1, 2012 and December 31, 2026.

E. **Exceptions**

The charges in this Schedule 17 are subject to the exceptions in the Settlement Agreements described below, as accepted by the Commission,[2] regarding the following grandfathered agreements ("GFAs" or "Agreements").

1. **Settlement Agreement among the Transmission Provider, Otter Tail Corporation d/b/a Otter Tail Power Company ("Otter Tail"), and Central Power Electric Cooperative, Inc. ("CPEC"), regarding Agreement No. 297**

Neither CPEC nor Otter Tail shall be assessed any Schedule 17 charges with regard to CPEC's loads and transmission rights under Agreement No. 297.

**2. Settlement Agreement among the Transmission Provider, Otter Tail Corporation d/b/a Otter Tail Power Company, and Minnkota Power Cooperative, Inc. ("Minnkota"), regarding Agreement Nos. 309, 313, 314 and 317**

Neither Otter Tail nor Minnkota shall be assessed any Schedule 17 charges with regard to Minnkota's loads, generation, and transmission rights under Agreement Nos. 309, 313, 314 and 317.

**3. Settlement Agreement among the Transmission Provider, Otter Tail Corporation d/b/a Otter Tail Power Company, Montana-Dakota Utilities Co. ("MDU"), Minnkota Power Cooperative, Inc. as agent for Northern Municipal Power Agency, and Northwestern Corporation d/b/a NorthWestern Energy ("NorthWestern"), regarding Agreement Nos. 311/273 and 320/274**

Neither Minnkota nor NorthWestern shall be assessed any Schedule 17 charges with regard to Minnkota's and NorthWestern's load, generation, and transmission rights under the Agreements Nos. 311/273 and 320/274. The load and/or generation of Minnkota and NorthWestern also shall not be used in the determination of any such charges to be paid by Otter Tail and/or MDU.

**4. Settlement Agreement among the Transmission Provider, Minnesota Power, and Minnkota Power Cooperative, Inc., regarding Agreement Nos. 284, 316 and 450**

Neither Minnesota Power nor Minnkota shall be assessed any Schedule 17 charges with regard to Minnkota's generation, load, and transmission rights under such Agreement Nos. 284, 316 and 450.

## III. RATE FORMULA

Each month the Transmission Provider shall determine the Energy and Operating Reserve Markets Administrative Service Cost Recovery Adder for the next month by dividing the Transmission Provider's budgeted Schedule 17 Costs[3, 4] or forecasted Schedule 17 Costs to be recovered under this Schedule 17 for that month, including true-up amounts from the prior month less the monthly credit determined in Section II.D of this Schedule 17, by the estimated sum of: 1) all MWh injected into the Transmission System by all Market Participants less the number of MWh derived pursuant to Schedule 17-B Section II.B.1 and Schedule 17-C Section II.B.1, including deliveries to the Transmission System from generation located both within the Transmission System and outside of the Transmission System; 2) all MWh extracted from the Transmission System by all Market Participants less the number of MWh derived pursuant to Schedule 17-B Section II.B.2 and Schedule 17-C Section II.B.2, including MWh delivered to loads located both within the Transmission System and outside of the Transmission System including all out and through transactions using the Transmission System; and, 3) all Bids or Offers for Energy that settle in the Day-Ahead Energy and Operating Reserve Markets, but do not actually inject MWh into or extract MWh from the Transmission System in the Real-Time Energy and Operating Reserve Markets, expressed in MWh less all Bids and Offers derived pursuant to Schedule 17-B Section II.B.3 and Schedule 17-C Section II.B.3 as discussed in Section II.A above. The formula shall be as follows:

$E_t$ = $(X_t + T_{t-1}$ - EMS_Prepayment$_{bt}$ - EMS_Prepayment$_{et})/(L_t + G_t + V_t)$ **where:**

t = Effective month.

*E* = Energy and Operating Reserve Markets Support Administrative Service Cost Recovery Adder in dollars per MWh.

T = True-up amount from prior month defined as the difference between Actual Schedule 17 Costs and Actual Schedule 17 Revenue, where

"Actual Schedule 17 Costs" equal the sum of the Energy Market Support Cost Components A.1 through A.7 less A.8 for the prior month.

"Actual Schedule 17 Revenue" equals the Energy Market Support Administrative Service Cost Recovery Adder for the prior month x (Schedule 17 Injected MWh for the prior month + Schedule 17 Extracted MWh for the prior month + Schedule 17 Virtual MWh for the prior month), where

"Schedule 17 Injected MWh" equals all Actual Energy Injections by all Market Participants, including deliveries to the Transmission System from generation located within the Transmission System and outside of the Transmission System.

"Schedule 17 Extracted MWh" equals all Actual Energy Withdrawals by all Market Participants, including MWh delivered to loads located within the Transmission System and outside of the Transmission System.

"Schedule 17 Virtual MWh" equals all Bids or Offers for Energy that were settled in the Day-Ahead Energy and Operating Reserve Markets, but did not actually inject MWh into or extract MWh from the Transmission System in the Real-Time Energy and Operating Reserve Markets

$\text{EMS-Prepayment}_b$ = Exit $\text{Fee}_{17b}$ / 180 months, where:

Exit $\text{Fee}_{17b}$ equals the balance as of May 31, 2011 of the deferred revenue account associated with the Withdrawal Obligation defined in Schedule 17-B of this Tariff.

$\text{EMS-Prepayment}_c$ = Exit $\text{Fee}_{17c}$ / 180 months, where:

Exit $\text{Fee}_{17c}$ equals the balance as of December 31, 2011 of the deferred revenue account associated with the Withdrawal Obligation defined in Schedule 17-C of this Tariff.

$X$ = Budgeted Schedule 17 Costs or forecasted Schedule 17 Costs, defined as A.1 + A.2 + A.3 + A.4 + A.5 + A.6 + A.7 – A.8, where:

A.1 = Sum of [Operation Expense (401) + Maintenance Expense (402) + Taxes Other Than Income Taxes (408)] directly charged to Schedule 17 accounts ("Direct Schedule 17 Costs").

Direct Schedule 17 Costs are limited to operating expenses associated with the provision of Energy and Operating Reserve Markets Support Administrative Services, including, but not limited to, unit commitment, unit dispatch, Day-Ahead Energy and Operating Reserve Markets and Real-Time Energy and Operating Reserve Markets. Direct Schedule 17 Costs exclude costs allocated to Schedule 1, Schedule 10 and Schedule 16.

A.2 = Sum of [Operation Expense (401) + Maintenance Expense (402) + Taxes Other Than Income Taxes (408)] not directly charged to Schedule 1, Schedule 10, Schedule 16 or Schedule 17 accounts ("Indirect Costs") x Operating Expense Allocation Factor - Schedule 17, where:

Operating Expense Allocation Factor – Schedule 17 = Base Wages 17 / (Base Wages 1 + Base Wages 10 + Base Wages 16 + Base Wages 17), where:

Base Wages 1 = Administrative and General Salaries (401.920) directly charged to Schedule 1 accounts exclusive of fringe benefits

Base Wages 10 = Administrative and General Salaries (401.920) directly charged to Schedule 10 accounts exclusive of fringe benefits

Base Wages 16 = Administrative and General Salaries (401.920) directly charged to Schedule 16 accounts exclusive of fringe benefits

Base Wages 17 = Administrative and General Salaries (401.920) directly charged to Schedule 17 accounts exclusive of fringe benefits

Indirect Costs are the operating expenses associated with corporate support functions, including but not limited to the Transmission Provider's executive, facilities, finance and human resources support functions. Indirect Costs exclude any costs of the Transmission Provider that are directly charged to a Schedule 1, Schedule 10, Schedule 16 or Schedule 17 operating expense account. As such, Indirect Costs exclude any costs recovered under Variable A.1 in this Schedule 17.

A.3 = Depreciation Expense (403) directly charged to Schedule 17 accounts (account 403, Transmission Plant sub-account 403.017) and amortization expense (account 405) directly charged to Schedule 17 account. This account includes charges for amortization of intangible or other electric utility plant which does not have a definite or terminable life and which is not subject to charges for depreciation expense.

Depreciation expense directly charged to Schedule 17 is maintained in account 403, Transmission Plant sub-account 403.017 of MISO's internal books and records. Sub-account 403.017 includes depreciation expense associated with certain assets for the Midwest Market Initiative that were not solely assigned to either Schedule 16 or Schedule 17 and therefore were allocated between Schedule 16 and Schedule 17 based on the ratio of plant closed to Schedule 16 and Schedule 17. Variable A.3 under this Schedule

17 excludes depreciation directly charged to Schedule 1, Schedule 10 and Schedule 16 accounts as well as depreciation associated with general plant accounts.

Amortization expense directly charge to Schedule 17 is maintained in account 405, Transmission Plant sub-account 405.017 of MISO's internal books and records. Sub-account 405.017 includes amortization expense associated with certain assets for the Midwest Market Initiative that were not solely assigned to either Schedule 16 or Schedule 17 and therefore were allocated between Schedule 16 and Schedule 17 based on the ratio of plant closed to Schedule 16 and Schedule 17. Variable A.3 under this Schedule 17 excludes amortization directly charged to Schedule 1, Schedule 10 and Schedule 16.

As enhancements to MISO's energy market systems are completed the new energy market-related assets will be added to this sub-account (403.017) based on use studies. The results of such use studies for each enhancement completed will be posted on MISO's website. Any changes to the use study findings would require a Section 205 filing to change the allocated amount of depreciation associated with the affected enhancement or enhancements. MISO will provide support for these study findings upon request of stakeholders or Market Participants.

A.4 = Depreciation Expense (403) and amortization expense (405) not directly charged to Schedule 1, Schedule 10, Schedule 16 or Schedule 17 accounts ("General Plant Depreciation") x Operating Expense Allocation Factor – Schedule 17. Amortization expense (account 405) includes charges for amortization of intangible or other electric utility plant which does not have a definite or terminable life and which is not subject to charges for depreciation expense.

A.5 = Sum of [Interest on Long-Term Debt (427) + Amortization of Debt Discount and Expense (428)] directly charged to Schedule 17 accounts. The interest expense directly charged to Schedule 17 account number 427 includes interest expense associated with all senior, unsecured notes authorized by the Commission and issued by MISO.

All interest expense not associated with the above debt obligations of the Transmission Provider and all interest income earned by the Transmission Provider are included in the category Indirect Interest Expense.

The amortization of debt discount and expense directly charged to Schedule 17 account number 428 includes amortization of debt discount and expense associated with all senior, unsecured notes authorized by the Commission and issued by MISO.

All amortization of debt discount and expense not associated with the above debt obligations of the Transmission Provider is included in the category Indirect Interest Expense.

Variable A.5 under this Schedule 17 excludes interest on long-term debt and amortization of debt discount and expense directly charged to Schedule 1, Schedule 10 and Schedule 17.

A.6 = Sum of [Interest and Dividend Income (419) + Interest on Long-Term Debt (427) + Amortization of Debt Discount and Expense (428) + Other Interest Expense (431)] not directly charged to Schedule 1, Schedule 10, Schedule 16 or Schedule 17 accounts ("Indirect Interest Expense") x Operating Expense Allocation Factor – Schedule 17

Variable A.6 under this Schedule 17 excludes interest on long-term debt and amortization of debt discount and expense directly charged to Schedule 17, as well as interest on long-term debt and amortization of debt discount and expense directly charged to Schedule 1, Schedule 10 and Schedule 16.

A.7 = Regulatory Debits (407.3) directly charged to Schedule 17

A.8 = Regulatory Credits (407.4) directly charged to Schedule 17

G = Estimated MWh for all MWh injected into the Transmission System by all Market Participants less the number of MWh derived pursuant to Schedule 17-B Section II.B.1 and Schedule 17-C Section II.B.1, including deliveries to the Transmission System from generation located within the Transmission System and outside of the Transmission System.

L = Estimated MWh extracted from the Transmission System by all Market Participants less the number of MWh derived pursuant to Schedule 17-B Section II.B.2 and Schedule 17-C Section II.B.2, including MWh delivered to loads located within the Transmission System and outside the Transmission System.

V = Estimated MWh of all Bids or Offers for Energy that settle in the Day-Ahead Energy and Operating Reserve Market, but do not actually inject MWh into or extract MWh from the Transmission System in the Real-Time Energy and Operating Reserve Market less all Bids and Offers derived pursuant to Schedule 17-B Section II.B.3, and Schedule 17-C Section II.B.3.

The depreciation rates to be used for calculating depreciation expense for variables A.3 and A.4 above are a function of when the asset is placed into service. For assets placed into service prior to June 1, 2009, the depreciation rates are as follows:

| Asset | Life | Rate (percent) |
|---|---|---|
| General Hardware | 3 years | 33.33 |
| ICCS Hardware | 6 years | 16.67 |
| Market Hardware | 6 years | 16.67 |
| General Software | 5 years | 20.00 |
| ICCS Software | 7 years | 14.29 |
| Market Software | 7 years | 14.29 |
| Furniture & Fixtures | 7 years | 14.29 |
| Telecommunications | 7 years | 14.29 |
| Leasehold Improvements | 20 years | 5.00 |

For assets placed into service on or after June 1, 2009, the depreciation and amortization rates are as follows:

| Asset | Life | Rate (percent) |
|---|---|---|
| General Hardware | 3 years | 33.33 |
| ICCS Hardware (Commodity) | 3 years | 33.33 |
| ICCS Hardware (Enterprise) | 5 years | 20.00 |
| Market Hardware (Commodity) | 3 years | 33.33 |
| Market Hardware (Enterprise) | 5 years | 20.00 |
| General Software | 3 years | 33.33 |
| ICCS Software | 5 years | 20.00 |

| | | |
|---|---|---|
| Market Software | 5 years | 20.00 |
| Furniture & Fixtures | 7 years | 14.29 |
| Telecommunications | 7 years | 14.29 |
| Building | 20 years | 5.00 |
| Land* | | 20.00 |

*Life is not terminable amortizing cost over 5 years

Leasehold Improvements (Structural Modifications) - Lease Term

Leasehold Improvements (Affixed Equipment) lesser of 4 years or lease term

The terms "ICCS Hardware" or "ICCS Software" as used in the tables above are defined as the cost of hardware or software associated with the Transmission Provider supplying regional transmission service. The terms "Market Hardware" or "Market Software" as used in the tables above are defined as the cost of hardware or software associated with supporting the market-based, congestion management systems and processes of the Transmission Provider. "Commodity" hardware includes computer systems that provide economical but limited compute resources in support of standard workloads. These computer systems are typically built using standardized commodity parts. "Enterprise" hardware includes computer systems that provide support for programs that collectively serve the needs of multiple users, departments, or specialized applications – typically under heavy workloads. These computer systems are designed and built to address specific reliability, availability and scalability ("RAS") requirements. Costs for Market Hardware and Market Software are recorded to sub-accounts by cost recovery Schedule 16 direct costs, (4) Schedule 17 direct costs, or (5) indirect costs to be allocated for cost recovery purposes to Schedule 1, Schedule 10, Schedule 16 and Schedule 17 based on the allocation factor defined above. Direct costs are those related to the services associated with Schedule 1, Schedule 10, Schedule 16 or Schedule 17. Indirect costs are costs associated with corporate support functions, including but not limited to, the Transmission Provider's executive, facilities, finance and human resources functions.

Loan principal is recovered through depreciation variable A.4 as well as other line items.

## IV. CHARGES FOR MARKET PARTICIPANTS

For each month, the charges to Market Participants for the Service will be calculated by multiplying the Energy and Operating Reserve Markets Support Administrative Service Cost Recovery Adder effective in that month, as determined under the above rate formula, by the Market Participants' billing units for that month, expressed in MWh, as discussed in Section II.A above. A Market Participant's billing units will be calculated as the sum of their Day-Ahead MWh, adjusted for Financial Schedules, plus their Real-Time imbalance MWh, calculated as Real-Time MWh minus Day-Ahead MWh, adjusted for Financial Schedules. Details for calculating the billing units are defined in the Market Settlements Business Practice Manual.

A Market Participant with a Generation Resource or Load that is Pseudo-tied out of MISO will have the billing units, as discussed in Section II.A above, reduced by the lesser of the (a) Real-Time Financial Schedule, in MWh, or (b) all cleared Day-Ahead Virtual Transactions with the same Sink Point and Source Point Commercial Pricing Nodes as the Real-Time Financial Schedule.

1 The charges in this Schedule 17 are subject to the exceptions in the Settlement Agreements approved by the Order of the Commission dated June 27, 2005 in *Midwest Independent Transmission System Operator, Inc.*, 111 FERC ¶ 61,491 (2005).

2 *Midwest Independent Transmission System Operator, Inc.*, 111 FERC ¶ 61,491 (2005).

3 Schedule 17 costs are exclusive of other deferred costs which include, but are not limited to, costs associated with the integration of the Entergy Operating Companies, Cleco Power LLC, South Mississippi Electric Power Association, Lafayette Utilities Systems and East Texas Electric Cooperative that will be recovered over a five-year period beginning on the date of the integration of the first Entergy Operating Company.

4 Schedule 17 costs are exclusive of other deferred costs.

# 278

A
B

U. S. DEPARTMENT OF AGRICULTURE
RURAL ELECTRIFICATION ADMINISTRATION

REA BORROWER DESIGNATION Kentucky 62 Big Rivers

THE WITHIN Agreement for Transmission and Transformation Capacity dated April 11, 1975, between Big Rivers and City of Henderson Utility Commission

SUBMITTED BY THE ABOVE DESIGNATED BORROWER PURSUANT TO THE TERMS OF THE LOAN CONTRACT, IS HEREBY APPROVED SOLELY FOR THE PURPOSES OF SUCH CONTRACT.

FOR THE ADMINISTRATOR

DATED OCT. 8 1975

DAVID H. ASKEGAARD
Acting Administrator

10
1

FORM 284 REV 5-73

Attachment 1 for Henderson's
Response to
Commission Staff 8(b)

AGREEMENT FOR

TRANSMISSION AND TRANSFORMATION CAPACITY

THIS AGREEMENT, made and entered into as of the 11th day of April, 1975, by and betw BIG RIVERS ELECTRIC CORPORATION, a Kentucky corporation with offices in Henderson, Kentucky (BIG RIVERS) and CITY OF HENDERSON UTILITY COMMISSION, a municipal commission establi by the City of Henderson, Kentucky pursuant to KRS 96.520 (COMMISSION).

WITNESSETH THAT:

SECTION 1 - STIPULATIONS:

1.1 BIG RIVERS owns and operates an electric generation and transmission system with which it serves its member cooperatives in a 15 county area of Western Kentucky.

1.2 COMMISSION manages, operates and controls an electric generation, transmission and distribution system owned by the City of Henderson, Kentucky (City) with which it serves the inhabitants and customers of City, with generation and distribution facilities within the service area of City, additional generation facilities (Station Two) adjacent to BIG RIVERS Reid generating station in Henderson County, Kentuc (Reid Station), and 69 KV transmission facilities connecting said Station Two to City's service area.

1.3 BIG RIVERS plans to construct a 161-138 KV transmission line and appropriate substation and terminal facilities in order to interconnect its electric system with the electric system of Southern Indiana Gas & Electric Company, an Indiana electric utility (SIGECO). The 161 KV transmission line will extend from BIG RIVERS' Reid Station to a transformer substation near the northern boundary of City's service area. BIG RIVERS' substation will include a 161-138 KV transformer to be used for its interconnection with SIGECO, and a 161-69 KV transformer to be used for its electric service in the state of Kentucky, and as provided in this Agreement.

1.4 COMMISSION desires to acquire the right to use a portion of the capacity of BIG RIVERS' 161-69 KV transformer and related substation facilities and of the 161 KV transmission line connecting said substation to the Reid Station, in order to transmit electricity from City's Station Two to its service area. In exchange therefor, COMMISSION is willing to contribute to the costs of acquisition and construction of said 161 KV transmission line and the 161-69 KV transformer and related substation facilities, and to the costs of operation and maintenance thereof as provided in this Agreement.

1.5 BIG RIVERS is willing to grant to COMMISSION the use of a portion of the capacity of said 161 KV transmission line and 161-69 KV transformer and related substation facilities, under the terms and conditions, and for the considerations recited in this Agreement.

SECTION 2 - FACILITIES:

2.1 Transmission: BIG RIVERS will acquire necessary transmission line right-of-way and construct thereon a 161,000 KV transmission line with minimum of 795 MCM ACSR conductor, from the point of the Paradise bay at Big Rivers Reid Station to the 161-138 KV and 161-69 KV transformer substation referred to in 2.2 hereof.

2.2 BIG RIVERS will acquire an adequate substation site within the vicinity of Larue Road, in Henderson County, Kentucky, and will construct thereon a substation and related facilities, including a 161-138 KV transformer, with which it will provide for the interconnection of its electric system with that of SIGECO, and a 161-69 KV transformer of 30/40/50 MVA capacity, with which it will serve its needs and will provide capacity to COMMISSION under the terms of this Agreement. The 161-69 KV transformer will be physically identified as # G-1 and the 161 KV transmission line as # 16-A.

2.3 BIG RIVERS will complete construction of said transmission and transformation facilities on or about January 1, 1976 and will commence the transmission and transformation services to be provided to COMMISSION under the terms of this Agreement as soon as said facilities and the facilities to be provided by SIGECO are completed and connected.

SECTION 3 - OPERATION AND MAINTENANCE:

3.1 During the term of this Agreement, BIG RIVERS will operate and maintain said 161 KV transmission line and 161-69 KV transformation facilities so as to provide to COMMISSION the transmission and transformation capacity as recited in Section 4 hereof.

SECTION 4 - TRANSMISSION AND TRANSFORMATION SERVICES TO COMMISSION:

4.1 Upon commencement by BIG RIVERS of the operation of the 161 KV transmission and 161-69 KV transformation facilities referred to in Section 2 hereof, and for the term of this Agreement, COMMISSION shall be entitled to the exclusive use of one-half of the transformation capacity of the 161-69 KV transformer and related substation facilities referred to in Section 2 hereof, and to an equivalent amount of capacity in the 161 KV transmission line and the switch-bay connections thereof to Reid Station and Station Two, for purposes of transmitting electric power and energy between Station Two and City's electric service area. Metering of power and energy transmitted to COMMISSION under this Agreement shall be at COMMISSIONS substation meters, with transmission losses to be borne t COMMISSION as provided, from time to time, by the parties' inter-connection agreement.

SECTION 5 - COSTS:

5.1 COMMISSION shall pay to Big Rivers one-half of the total costs to Big Rivers for acquisition and construction of the 161-69 KV transformer and related substation facilities and

8 one-tenth of the total costs to Big Rivers of the acquisition

9 and construction of the 161 KV transmission line and related switch-bay facilities. Commission shall not pay any costs associated with the acquisition and construction of the 161-138 transformer and related substation facilities or the 138 KV transmission line connecting said transformer to the SIGECO interconnection. The costs of facilities associated with both the 161-138 KV and 161-69 KV transformers shall be equitably apportioned to the costs of such transformers. The costs herein referred to shall include also the costs of land and easements acquired in connection with such transmission and substation facilities.

Such costs shall be paid by Commission to Big Rivers as follows:

(a) Upon the execution of this Agreement, $80,000.00.
(b) On May 31, 1975, $80,000.00.
(c) On November 30, 1975, one-half of the balance due (as then determined by contracts and/or estimates).
(d) On May 31, 1976, the balance due.

5.2 During the term of this Agreement COMMISSION shall promptly pay to BIG RIVERS, upon monthly billing therefor, the following designated shares of all costs of operation, maintenance, repairs and replacements of the 161 KV transmission line and 161-69 KV

transformer, and related facilities referred to in Section 2 hereof, but exclusive of any costs applicable to the operation, maintenance, renewals and replacements of the 161-138 KV transformer and related substation facilities and all portions of the 138 KV transmission facilities referred to in Section 2. Commission's share of said costs shall be one-half of all such costs related to the 161-69 KV transformer and related substation facilities and one-tenth of all such costs related to the 161 KV transmission line and related switch-bay connections to Reid Station and Station Two. 1
Energy consumed in the operation of the 161-69 KV transformer (transformer losses) shall be included as costs of operation.

SECTION 6 - GENERAL PROVISIONS:

6.1 Construction and Operating Standards: The facilities which are the subject of this Agreement shall be constructed, operated and maintained in accordance with standards and specifications at least equal to those provided by the National Electric Safety Code of the American National Standards Institute, and as required by the Rural Electrifications Administration and any regulatory authorities having jurisdiction thereof.

6.2 Inspections, Right of Access: Each party hereto shall permit the duly authorized representatives and employees of the other party to enter upon its premises for the purpose of reading or checking meters, inspecting, testing, repairing, renewing or replacing any or all of the facilities and equipment owned by the other party located on such premises, or for the purpose of performing any of the work necessary in order to carry out the provisions of this Agreement. Such entries shall be conducted so as not to interfere with the use of the other party's facilities. Each party shall be responsible for the safety of its own representatives and employees when on the premises of the other pursuant to the right of access granted herein, and shall hold harmless and indemnify the party granting access from any loss or damage whatsoever by reason of any injury, including death, of such representatives and/or employees, unless the same shall be due to the negligence or willful misconduct of the party granting such access or its authorized agents or employees.

6.3 Relationship of the Parties: The terms of this Agreement shall not be construed as an agreement for partnership, joint venture, association or other relationship whereby either party shall be responsible for the obligations and/or liabilities of the other party hereto. Neither party to this Agreement shall be liable for any act, omission or legal obligation of the other party hereto. Neither party to this Agreement shall, by reason of the provisions hereof, be deemed a principal, agent, subcontractor or employee of the other party hereto, nor shall either party to this Agreement have the authority to bind the other party to this Agreement to any contract or any other obligation, without specific written authority therefor.

6.4 Uncontrollable Forces: Neither party hereto shall be considered in default or breach with respect to any obligation of this Agreement if prevented from fulfilling such obligation by reason of an uncontrollable force. Any party unable to fulfill any obligation by reason of uncontrollable forces shall exercise due diligence to remove such disability as soon as reasonably possible. The term uncontrollable force shall mean any force which is not within control of any party to this Agreement, and which by exercise of due diligence and foresight would not have reasonably been avoided, including but not limited to: an act of God, fire, flood, earthquake, explosion, strike, sabotage, an act of the public enemy, civil or military authority, including court orders, injunctions and orders of government agencies having proper jurisdiction, insurrection or riot, an act of the elements, failure of equipment, or inability to obtain or ship materials or equipment because of the effect of similar causes on suppliers or carriers.

6.5 Arbitration: Any controversy or claim arising out of, or relating to this Agreement or to the breach thereof, may be submitted to arbitration at the time, in the manner and upon the terms agreed upon by the parties. Arbitration shall not be considered the sole or exclusive means of settling controversies which may arise under the terms and provisions of this Agreement, nor shall arbitration be considered a condition precedent to any action in court of law or equity or proceedings before any governmental agency or regulatory body having jurisdiction thereof.

6.6 Default: In the event of a default by either party in the performance of any one or more of the provisions of this Agreement, the aggrieved party shall, in addition to the remedies specified in this Agreement, have the right to use and employ all rights and remedies available through courts of law and/or equity, governmental agencies and/or regulatory bodies having jurisdiction thereof.

6.7 Waiver: The failure of either party to insist in any one or more instances upon strict performance of any of the provisions of this Agreement or to take advantage of any of its rights hereunder shall not be construed as a waiver of any such provisions or the relinquishment of any such rights, but the same shall continue and remain in full force and effect.

6.8 Notices: Any payment, written notice, demand or request required or permitted under this Agreement shall be deemed properly given to or served upon the recipient when posted through the regular United States mail affixed with postage and properly addressed as follows:

To BIG RIVERS: President, Big Rivers Electric Corporation
P. O. Box 24
Henderson, Kentucky 42420

To COMMISSION: General Manager, Municipal Power & Light
P. O. Box 8
Henderson, Kentucky 42420

SECTION 7 - OTHER PROVISIONS:

7.1 Insurance: BIG RIVERS shall insure the transformation and transmission facilities which are the subject of this Agreement against loss or damage by fire, storm or other insurable casualty, in some good and solvent insurance company or companies, to the maximum insurable value thereof, with loss payable clause to COMMISSION as its interest may, from time to time, appear, and the costs of such insurance shall be considered a part of the operating costs of such facilities and shall be apportioned to the parties as provided in Section 5 of this Agreement.

7.2 Term and Termination: The term of this Agreement shall commence upon the execution hereof by BIG RIVERS and COMMISSION and shall terminate thirty (30) years after the date of commencement of transformation and transmission services to COMMISSION under the terms of this Agreement. Upon termination of this Agreement COMMISSION shall have no further rights in or to any of the transmission and transformation facilities which are the subject of this Agreement.

7.3 Sale or Other Disposition of Facilities:

If, during the term hereof, BIG RIVERS desires to sell or otherwise dispose of the transformation and transmission facilities which are the subject of this Agreement, it shall first give COMMISSION notice in writing of its desire or intention to make such sale or disposition, specifying therein the terms and consideration to be received therefor, and thereafter, COMMISSION shall have a period of ninety (90) days within which to elect to purchase or otherwise acquire said facilities in accordance with the consideration and provisions of said offer. In the event COMMISSION shall fail to exercise its right to purchase or otherwise acquire said facilities, then BIG RIVERS shall be entitled to proceed with the sale or other disposition to another party or parties, provided that if such sale or other disposition by BIG RIVERS is not made within one year after the expiration of such ninety (90) day period, no such sale or other disposition shall be made thereafter without again first offering the same to COMMISSION as hereinabove provided. Any sale, assignment or other disposition by BIG RIVERS of the transformation and/or transmission facilities through which capacity is provided to COMMISSION under the provisions of this Agreement, to any party other than COMMISSION shall be made subject to all of the rights, obligations, terms and conditions of this Agreement and any amendments or additions thereto which are then applicable, and it shall be a condition of such sale or other disposition that the purchaser or acquirer thereof assume all of the obligations of BIG RIVERS under the terms of this Agreement.

7.4 Expansion of Facilities: In the event that BIG RIVERS shall, during the term of this Agreement, elect to construct additional 161-69 KV transformation capacity at the substation site herein referred to, COMMISSION shall have the right and option to participate in such expansion by contributing to the costs of acquisition, construction, operation, maintenance, renewals and replacements thereof in direct proportion to the share of the capacity of such additional transformer and related facilities as is reserved to COMMISSION. The amount of capacity available to COMMISSION under this option shall not exceed the lesser of one-half the total capacity of such additional transformer and related facilities or 25 MVA. The option herein granted is for transformation capacity only and specifically excludes any additional capacity in the 161 KV transmission facilities referred to in this Agreement. The portion of costs of acquisition and construction of the additional transformer and related facilities to be paid by COMMISSION shall be reduced in proportion to the number of years remaining in the term of this Agreement at the time of completion of construction of such additional transformer and related facilities, as compared to thirty (30) years.

7.5 Default:

Should COMMISSION fail to make any payment herein required then, in addition to any other remedies which BIG RIVERS may have at law or equity, or with any administrative or regulatory body, board, commission, agency or authority, BIG RIVERS shall have the right upon thirty (30) days written notice to COMMISSION to terminate COMMISSION'S use of the transformation and transmission facilities herein referred to, which use shall, at BIG RIVERS' option, remain terminated until such default is remedied by payment of all amounts past due, with interest at ten percent (10%) per annum from due date until paid.

Should BIG RIVERS fail to perform any provision of this Agreement on its part then, in addition to any other remedies which COMMISSION may have at law or equity or with any administrative or regulatory body, board, commission, agency or authority, commission shall have the right, upon thirty (30) days written notice to BIG RIVERS, to cease making any payments due hereunder until such default is remedied by BIG RIVERS.

7.6 Amendment:

No amendments of this Agreement shall be effective unless reduced to writing and executed by the parties hereto. It is understood that BIG RIVERS may not agree to any amendment, modification or alteration of this Agreement without first obtaining approval of the Administrator of the Rural Electrification Administration.

7.7 Severability:

In the event that any part of this Agreement is declared illegal or no longer in force by reason of an order issued by a court or regulatory body or competent jurisdiction, all remaining portions of this Agreement which are not affected by such order shall continue in full force and effect. This Contract shall be interpreted under the laws of the State of Kentucky.

7.8 Assignment:

This Agreement shall be binding upon the parties hereto, their respective successors and assigns. Provided, however that this Agreement shall not be assigned by either party (except for an assignment by BIG RIVERS to the United States of America) without the written consent of the other party, and any such assignment shall be subject to the provisions of Section 7.3 of this Agreement.

7.9 Approvals:

This Agreement shall be subject to the approval of all local, state or federal regulatory bodies having jurisdiction thereof and shall become effective only upon the execution thereof by the parties and approval by the Administrator of the Rural Electrification Administration.

SECTION 8 - CONDITIONS PRECEDENT:

8.1 This Agreement shall be subject to the condition precedent that BIG RIVERS is able to obtain a loan from the Rural Electrification Administration of sufficient sum, together with the amounts to be paid by COMMISSION hereunder, to enable it to finance the construction and acquisition of all transformation and transmission facilities herein referred to.

SECTION 9 - AUTHORITY TO EXECUTE:

9.1 This Agreement is executed by the duly authorized officers or representatives of the parties pursuant to authority granted to each of them by the lawful action of their respective official commissions or boards.

EXECUTED at Henderson, Kentucky, this 11th

of April, 1975.

BIG RIVERS ELECTRIC CORPORATION

By: [signature]
President

ATTEST:

[signature]
Secretary

CITY OF HENDERSON UTILITY COMMISSI

By: [signature]
Chairman

ATTEST:

[signature]
Secretary

This Instrument Prepared by

[signature]
of WEST AND TERNES, CHARTERED
Suite 380 - Imperial Building
110 Third Street
Henderson, Kentucky 42420

LOUIS B. HATCHETT
Chairman

W. T. LATTA
Vice-Chairman

DUDLEY H. EVERSON
Secretary-Treasurer

B. L. PERRY
General Manager

# MUNICIPAL POWER & LIGHT

OPERATED BY CITY UTILITY COMMISSION
P.O. BOX 8
HENDERSON, KENTUCKY 42420
(502) 826-2726

July 30, 1984

Mr. William H. Thorpe, General Manager
Big Rivers Electric Corporation
201 Third Street
Henderson, Kentucky 42420

Re: Letter Agreement - HMP&L Contract with SEPA

Dear Bill:

Hereinafter set forth is the mutual understanding of Big Rivers Electric Corporation and the Utility Commission for the City of Henderson, Kentucky regarding the contract to be executed by the Utility Commission for the purchase of peaking capacity and associated energy from the Southeastern Power Administration effective July 1, 1984 (HMP&L-SEPA Contract). The Utility Commission will enter into the HMP&L-SEPA contract in reliance upon Big Rivers' concurrent commitments as expressed herein.

1. Big Rivers will perform all the duties and obligations assigned to it in the HMP&L-SEPA contract.

2. Big Rivers will, on an annual basis, accept and pay for all capacity and associated energy under the HMP&L-SEPA contract not reserved nor scheduled by HMP&L during the entire term of such contract.

3. HMP&L will not reserve any capacity nor take any associated energy under the HMP&L-SEPA contract prior to June 1, 1985.

4. Not later than October 31 of each year from 1984 through 1993, inclusive, HMP&L will notify Big Rivers in writing setting forth the amount of capacity that HMP&L elects to reserve and take under the HMP&L-SEPA contract during its next succeeding fiscal year.

5. Big Rivers will provide firm transmission to deliver energy scheduled by HMP&L under the HMP&L-SEPA contract through its transmission lines with compensation to Big Rivers in accordance with Section 2.2, Article 2 of Service Schedule F in the Big Rivers-Hoosier Energy-Henderson Municipal Power and Light-Southern Illinois Power Cooperative interconnection agreement dated April ~~30~~, 1968 as amended.
1 mk,

**Attachment 1 for Henderson's Response to Commission Staff 8(c)**

6. Big Rivers agrees that thirty-three and one-third percent (33 1/3%) of the peaking capacity purchased by HMP&L under the HMP&L-SEPA contract will qualify as "firm capacity purchased from others" under Numerical Paragraph 2.1(c) of the System Reserves Agreement between the parties dated January 1, 1984.

7. HMP&L will pay SEPA directly for all charges incurred under the HMP&L-SEPA contract according to its terms and Big Rivers will pay HMP&L in a like manner for capacity reserved and energy scheduled by Big Rivers.

If you concur with the foregoing terms and conditions, please execute this letter in behalf of Big Rivers in the space provided and return same to me. Your prompt attention to this matter is appreciated.

Very truly yours,

B. L. Perry

B. L. Perry, General Manager

BIG RIVERS ELECTRIC CORPORATION

By Morton Henshaw

RESOLUTION

July 30, 1984

The Utility Commission for the City of Henderson, Kentucky, in special session this 30th day of July, 1984, having considered and found acceptable a contract designated as Contract No. 89-00-1501-638 with Southeastern Power Administration for the purchase of power, hereby ratifies and confirms the execution of said Contract by Louis B. Hatchett, Chairman, with the Southeastern Power Administration for and in behalf of the Utility Commission for the City of Henderson, Kentucky.

Louis B. Hatchett

Louis B. Hatchett, Chairman

ATTEST:

Dudley H. Everson

Dudley H. Everson, Secretary

Big Rivers
ELECTRIC CORPORATION

201 Third Street
P.O. Box 24
Henderson, KY 42419-0024
270-827-2561
www.bigrivers.com

Rec. 9/22/2010 AM
@ HMPL

September 22, 2010

Mr. Gary Quick
General Manager
Henderson Municipal Power & Light
P. O. Box 8
Henderson, KY 42419-0008

Dear Gary:

As you may know, Big Rivers' hearing before the Public Service Commission in its case seeking authority to transfer functional control of its transmission system to Midwest Independent Transmission System Operator, Inc. ("Midwest ISO") concluded September 15, 2010. In order to implement Big Rivers' scheduled December 1, 2010, integration into the Midwest ISO, Big Rivers submitted Commercial Model data to the Midwest ISO on September 15, 2010, and on September 22, 2010, submitted two required certifications regarding the registration of the Station Two generation asset and the City of Henderson load. Pursuant to those submissions, Big Rivers will act as the Market Participant on behalf of the City of Henderson load and Station Two. This designation will have no impact on Big Rivers' performance of its contractual obligations under its agreements with the City of Henderson regarding Station Two. Please let me know if you have any questions, or if we can provide you further information.

Sincerely yours,

Mark A. Bailey

Mark A. Bailey
President and CEO
Big Rivers Electric Corporation

**Attachment 1 for Henderson's Response to Commission Staff 8(e)**

Gary Quick

---

**From:** Mark Bailey [Mark.Bailey@bigrivers.com]
**Sent:** Monday, September 27, 2010 3:14 PM
**To:** Gary Quick
**Cc:** cbredenbeck@midwestiso.org
**Subject:** RE: BREC Letter

Hello Gary:

You asked in the following e-mail message of September 24, 2010, how Big Rivers submitted the registration request for the Station Two capacity and related energy. Big Rivers, as Market Participant, has submitted to Midwest ISO registration forms for Station Two Unit 1 (153 MW) and Unit 2 (159 MW). The HMP&L load is registered as a part of Big Rivers' load. This was accomplished on or about September 15, 2010, as required by Midwest ISO to assure integration of Big Rivers into Midwest ISO by December 1, 2010, prior to expiration on December 31, 2010, of Midwest ISO Attachment RR Contingency Reserve service to Big Rivers for all generators operated by it. As I noted in my letter of September 22, 2010, this registration will have no negative impact on Big Rivers' performance of its contractual obligations under its agreements with the City of Henderson regarding Station Two. Please let me know if we may provide you further information.

Mark

---

**From:** Gary Quick [mailto:gquick@hmpl.net]
**Sent:** Friday, September 24, 2010 11:46 AM
**To:** Mark Bailey
**Cc:** 'Cheryl A. Bredenbeck'; Wayne Thompson
**Subject:** FW: BREC Letter

Good Morning Mark:

I plan to respond to your September 22 letter concerning MISO, but after I received your letter I had several questions for MISO. Below is an email from Cheryl and she responded to some of my questions. However, please note her comment below concerning my questions about the registration of Station Two capacity and related energy. Cheryl suggested that I contact you; can you let me know how Big Rivers submitted the registration request for the Station Two capacity and related energy? As we discussed with you and your staff, if HMP&L participates in MISO we will register our annual reserved capacity and related energy. We assume Big Rivers has registered its annual allocated capacity and related energy. We have a meeting today with TEA and I'm sure they will need to have this information as they go forward as HMP&L's Market Participant.

In advance, thanks for your help. Gary

---

**From:** Cheryl A. Bredenbeck [mailto:cbredenbeck@midwestiso.org]
**Sent:** Friday, September 24, 2010 10:22 AM
**To:** Gary Quick
**Cc:** Wayne Thompson; 'Sam H. Doaks'; Randall Redding; 'Haynes, Greg'; Snell, Virginia; 'Mark Bailey'
**Subject:** RE: BREC Letter

Hi Gary,

I do have a copy of your referenced May 27th e-mail. As you recall at the time of those April to May discussions, Big Rivers was preparing for a September 1 integration (that was later postponed) and the timeline for Market Participants to register assets located in the Balancing Authority was June 15th, two and one-half months before the initial planned Big Rivers integration. The postponed integration date is now December 1 with the corresponding deadline for Market Participants (new and existing) to register assets falling the same two and one-half months before, or September 15. If you look at the materials Midwest ISO provided and reviewed in our visit to your offices back on April 27th, Slide 27 of those materials contains the registration process and due dates for Market Participant registration materials to be submitted.

In order for a Big Rivers Balancing Authority to join the Midwest ISO market all generation and load must be registered by Market Participants. Each Market Participant submits asset registration forms and becomes financially responsible for the assets it registers. As you recognize in your message below, under the Midwest ISO process the only way assets can be registered is by a Market Participant. On September 15 Midwest ISO only received the registration from an existing Market Participant – namely Big Rivers. Your May 27th e-mail confirmed that you were agreeable to Big Rivers registering the City's assets. Therefore, we have processed the Big Rivers September 15th Registration accordingly.

As we discussed back in April, the City of Henderson, as an asset owner, can certainly register once you've met the requirements of a Market Participant or elect to have a different Market Participant register these assets on your behalf in a future modeling cycle. The timing of the registration needs to be compliant with the attached Midwest ISO model deadlines presentation. These deadlines are also posted on our website. We would be happy to assist you in better understanding that Market Participant and asset registration process if you would like.

With regard to specific questions as to how the capacity and energy was registered you would need to contact Mr. Bailey at Big Rivers.

Sincerely,

Cheryl

---

**From:** Gary Quick [mailto:gquick@hmpl.net]
**Sent:** Thursday, September 23, 2010 12:54 PM
**To:** Cheryl A. Bredenbeck
**Cc:** Wayne Thompson; 'Sam H. Doaks'; Randall Redding; 'Haynes, Greg'; Snell, Virginia; 'Mark Bailey'
**Subject:** BREC Letter

Good Morning Cheryl:

On May 27 of this year I sent you an email at 5:10pm concerning Henderson Municipal Power and Light's intentions in the event Big Rivers Electric Cooperation became a member of MISO. Henderson has also held several meetings with you, MISO staff, and Big Rivers concerning the various options available to Henderson related to how Henderson could participate in MISO. Our position concerning participation in MISO has not changed since our last communication.

Attached is a letter I received this morning from Mr. Bailey at Big Rivers concerning the Henderson Station Two generation units. Henderson needs to know how MISO is planning to register the Henderson units. As stated in the attached letter, Big Rivers informed us this morning that it will act as the Market Participant on behalf of the

City of Henderson, which is not consistent with our position and what we have clearly stated to MISO and Big Rivers.

Before we respond to Big Rivers, we need to know what MISO and Big Rivers have done, if anything, regarding the Henderson Station Two capacity, energy, and Market Participation. As we explained to MISO and Big Rivers, Henderson has always intended to register its annual reserved capacity and the related energy. Furthermore, we also informed MISO and Big Rivers that Henderson was considering two options regarding future Market Participation; first, Henderson would request MISO's approval to become a Market Participant or second, Henderson would retain an existing external Market Participant to represent Henderson.

Please let me know the details of how Big Rivers is requesting to join MISO regarding the registration of Henderson's Station Two units and the Market Participant responsibilities.

In advance, thank you. Gary

**Item 9)** **Refer to the Brown Testimony, pages 7-8, regarding MISO Tariff, Schedule 23. Provide a copy of Schedule 23.**

**Response)** See attached.

**Witness)** **Seth W. Brown**

# SCHEDULE 23
# RECOVERY OF SCHEDULE 10 AND SCHEDULE 17 COSTS FROM CERTAIN GFAs

**1. Background.**

The purpose of this Schedule 23 is to provide a mechanism for the direct cost recovery of Transmission Provider charges applicable to services provided to customers under Carved-Out GFAs. For the purposes of this Schedule 23, the Carved-Out GFAs shall be the grandfathered agreements which the Commission carved out from MISO's energy markets tariff in its September 16, 2004 order in Docket No. ER04-691 and which are listed on Attachment 1 to this Schedule 23. The customers responsible for such charges shall be the customers of the Transmission Owner, including for purposes of this Schedule 23 Independent Transmission Company Participants, under the Carved-Out GFA ("Carved-Out GFA Customers"). For the purpose of this Schedule 23, the term "Transmission Owner" shall include those entities listed as Transmission Owners in Attachment 1 of this Schedule 23.

**2. Recovery of Charges.**

**2.1 Direct Cost Recovery of Actual Schedule 10 and 17 Costs.** The amount to be collected from Carved-Out GFA Customers shall be a direct cost recovery of the actual Schedule 10 and 17 costs assessed to Transmission Owners for or on behalf of such Carved-Out GFA Customers by the Transmission Provider. The costs to be recovered shall be costs billed by the Transmission Provider on or after the effective date of this Schedule 23.

**Attachment 1 for Henderson's Response to Commission Staff 9**

2.2 **Monthly Billing.** Each month, the Transmission Provider shall bill the Carved-Out GFA Customers an amount equal to the amount absent Schedule 23 it would have billed the Transmission Owner under Section 7 of the Tariff for Schedules 10 and 17 charges associated with Carved-Out GFAs. The Transmission Owner shall provide the Transmission Provider with the necessary billing information for the Carved-Out GFA Customer (including load data for the Carved-Out GFA Customer, any adjustments to the Transmission Owner's load, and any credits received by the Transmission Owner under the Tariff relating to Schedule 10 and 17 charges applicable to Carved-Out GFAs on Schedule 23, Attachment 1) prior to invoicing such Carved-Out GFA Customer pursuant to this Schedule 23. The Transmission Provider shall withhold billing the Transmission Owners for such charges, provided that each Transmission Owner shall be responsible for such charges if not paid by the Carved-Out GFA Customer within the remittance requirements set forth in Section 7 of the Tariff. If a Carved-Out GFA Customer does not pay the invoice in full by the due date, the Transmission Provider and/or the affected Transmission Owner(s) may pursue payment in the appropriate forum. If a Transmission Owner seeks payment, the Transmission Provider shall cooperate with the Transmission Owner with regard to its collection efforts. If a Carved-Out GFA Customer that is a Market Participant receives a bill directly from MISO not under this Schedule 23 for Schedule 10 and 17 costs, the Transmission Provider shall not bill the Transmission Owner for these costs. In that event, Schedule 10 and 17 costs will not be recovered under this Schedule 23.

In no event shall a Transmission Owner recover Schedule 10 or 17 costs pursuant to a Carved-Out GFA listed on Attachment 1 to this Schedule 23 if the Transmission Provider is already recovering such Schedule 10 and 17 costs through other means. Each Transmission Owner recovering such costs through other means shall notify the Transmission Provider of that fact prior to invoicing.

2.3 **Filing of Service Agreement.** If the Carved-Out GFA Customer is not a Market Participant or a Transmission Customer or is not otherwise obligated to comply with the terms of this Tariff, then the Transmission Provider will file a service agreement, either executed or unexecuted, with the Commission to allow charges to the Carved-Out GFA Customer under this Schedule 23.

The Transmission Provider shall have the right to file an unexecuted agreement whether or not the Carved-Out GFA Customer requests that it be filed unexecuted. Each Transmission Owner shall cooperate with the Transmission Provider with regard to such filings and shall provide the Transmission Provider with information necessary to complete the service agreement.

2.4 **Payments to Transmission Owner.** If the Transmission Owner has paid Schedule 10 and/or 17 amounts which a Carved-Out GFA Customer was obligated to pay under this Schedule 23 and the Transmission Provider subsequently receives payment from the Carved-Out GFA Customer which duplicates the payment by the Transmission Owner in whole or in part, the Transmission Provider shall remit the payment to the appropriate Transmission Owner within fifteen (15) days of determining this duplicative payment.

The Transmission Provider shall provide any applicable interest that it collected from the Carved-Out GFA Customer; the Transmission Provider shall not be required to remit any other interest with regard to such payments.

2.5 **No Double Recovery.** Amounts may not be recovered under this Schedule 23 which are otherwise being recovered from the Carved-Out GFA Customer. The Transmission Provider shall verify, in its invoices or supporting detail for costs recovered under this Schedule 23, that the Schedule 10 and Schedule 17 charges billed to Carved-Out GFA Customers are not duplicative of costs already recovered directly under other provisions of the Tariff. Each applicable Transmission Owner shall provide, at the time of the initial bill for costs recovered under this Schedule 23, a certification stating that the Schedule 10 and 17 charges billed to its Carved-Out GFA Customers are not duplicative of costs already otherwise recovered by the Transmission Owner, and the Transmission Owner shall provide a breakdown of charges under the Carved-Out GFA demonstrating that no double recovery is occurring. If, as indicated on Schedule 23, Attachment 1, the Transmission Owner already recovers Schedule 10 costs under a Carved-Out GFA, the Transmission Provider will show on its invoice or supporting detail to the Carved-Out GFA Customer that Schedule 10 costs are not being recovered through this Schedule 23. Alternatively, if such Transmission Owner prefers to recover such Schedule 10 costs through this Schedule 23, it must show an adjustment to its charges under the applicable Carved-Out GFA invoice or supporting detail to remove the Schedule 10 costs. At the time of the above certifications and showings, the Transmission Owner and the Transmission Provider shall provide data and information to allow the Carved-Out GFA Customer to determine that there is no double recovery. The supporting detail for invoices shall include adequate information to allow the Carved-Out GFA Customers to shadow or back-calculate MISO and Transmission Owner invoices in order to ensure that no double billing or double collection of Schedules 10 or 17 have occurred, including, but not limited to, the schedule, product, ancillary reference number, reserved capacity, customer percent, load factor, and the billing month, along with the appropriate customer service contact name and number for any billing inquiries. The Transmission Owner and Transmission Provider also shall provide information in response to reasonable requests by Carved-Out GFA Customers necessary to ensure that there is no double recovery of costs covered by this Schedule 23. Any disputes concerning double recovery shall be governed by the dispute resolution procedures of Section 12 of the Tariff.

**2.6** **Credits.** The Transmission Owner must identify all credits it receives under the Tariff based on Schedule 10 and 17 charges applicable to the Carved-Out GFAs listed on Attachment 1 to this Schedule 23. The Transmission Owner must provide information concerning such credits to the Transmission Provider to enable the Transmission Provider to offset against charges under this Schedule 23 the value of such credits for each Carved-Out GFA. The amount the Transmission Provider invoices to each Carved-Out GFA Customer under Section 2.2 of this Schedule 23 shall be reduced by any such offsets.

2.7 **Information to Transmission Provider.** In addition to the information specified herein, each Transmission Owner shall provide to the Transmission Provider any other information needed to allow the Transmission Provider to bill the Transmission Owner's Carved-Out GFA Customers.

2.8 **Carved-Out GFA Customer Disputes.** If the Carved-Out GFA Customer disputes the load data provided by the Transmission Owner to the Transmission Provider, the Carved-Out GFA Customer and the Transmission Owner shall resolve such dispute among the Carved-Out GFA Customer and the Transmission Owner and any reconciliation of payments will be made between the Carved-Out GFA Customer and the Transmission Owner.

**ATTACHMENT 1**

**LIST OF CARVED-OUT GFAs**

**UNDER THIS SCHEDULE 23**

| GFA | Transmission | Customer | Contract |
|---|---|---|---|

| No. | Owner | Name | Title |
|---|---|---|---|
| 11 | Alliant Energy – Interstate Power and Light Company | Truman Public Utilities | Electric Service Agreement between Interstate Power Company and the City of Truman, Minnesota |
| 12 | Alliant Energy – Interstate Power and Light Company | Great River Energy (formerly Cooperative Power Association) | Transmission Utilization Agreement between Cooperative Power Association and Interstate Power Company |

| | | | |
|---|---|---|---|
| | | | and Amendment No. 1 |
| 14[1] | Alliant Energy – Interstate Power and Light Company | Northeast Missouri Electric Power Cooperative ("NEMO") | Interconnection and Transmission Service Agreement between Northeast Missouri Electric Power Cooperative and Iowa Southern Utilities Company, including First Amendment |

| GFA No. | Transmission Owner | Customer Name | Contract Title |
|---|---|---|---|

---

| | | | |
|---|---|---|---|
| 16[2] | Alliant Energy – Interstate Power and Light Company | Central Iowa Power Cooperative | IE/CIPCO Operating and Transmission Agreement and Appendices |
| 17[3] | Alliant Energy – Interstate Power and Light Company | Corn Belt Power Cooperative | Contract |
| 19 | Alliant Energy – Interstate Power | Union Electric (d/b/a AmerenUE) | Interchange Agreement and Appendix I |

| | | | |
|---|---|---|---|
| | and Light | | |
| | Company | | |
| 20 | Alliant Energy – Interstate Power and Light Company | Dairyland Power Cooperative | General Transmission Facilities Installation Agreement |

| GFA | Transmission | Customer | Contract |
|---|---|---|---|

| No. | Owner | Name | Title |
|---|---|---|---|
| 28 | Alliant Energy – Interstate Power and Light Company | Central Iowa Power Cooperative (CIPCO) | Agreement for Interconnection of Transmission Facilities |
| 29 | Alliant Energy – Interstate Power and Light Company | Central Iowa Power Cooperative (assigned rights by Southwestern Federated Power Cooperative) | Interconnection and Joint Construction Agreement |

| | | | |
|---|---|---|---|
| 30 | Alliant Energy – Interstate Power and Light Company | Central Iowa Power Cooperative (assumed contract from Eastern Iowa Light and Power Cooperative) | Interconnection and Joint Construction Agreement between Eastern Iowa Light and Power Company |
| 31 | Alliant Energy – Interstate Power and Light Company | Central Iowa Power Cooperative (assumed contract from Eastern Iowa Light and Power Cooperative) | Operating Agreement between Iowa Southern Utilities Company and Eastern Iowa Light and Power Cooperative |

| GFA No. | Transmission Owner | Customer Name | Contract Title |
|---|---|---|---|
| 35 | Alliant Energy – Interstate Power and Light Company | Central Iowa Power Cooperative ("CIPCO") | Interchange Agreement dated 11/5/68 |
| 36 | Alliant Energy – Interstate Power and Light | Central Iowa Power Cooperative (assigned rights by Southwestern | Contract dated 11/17/54 |

| | | | |
|---|---|---|---|
| | Company | Federated Power | |
| | | Cooperative) | |
| 41 | Alliant Energy – Interstate Power and Light Company | Dairyland Power Cooperative | Interconnection and Interchange Agreement between Dairyland Power Cooperative and Interstate Power Company, Dated 8/17/66, including Exhibits A-F, as amended |
| 179 | Hoosier | PECO Energy Co. (2 agreements) | Unit Power Sales Agreement (2/10/97) |

| GFA No. | Transmission Owner | Customer Name | Contract Title |
|---|---|---|---|
| | | | Unit Power Sales Agreement (7/24/97) |
| 185 | Hoosier | Wabash Valley Power Assoc., Inc. | Power Sales Agreement (10/28/87) |
| 186 | Hoosier | Indianapolis Power & Light Co. | Interconnection Agreement (12/1/81) |
| 254[5] | METC | Wolverine Power | Campbell Unit No. 3 Transmission |

| | | | |
|---|---|---|---|
| | | Supply Cooperative, Inc. ("WPSC") | Ownership and Operating Agreement, dated 8/15/80 |
| 255[5] | METC | Wolverine Power Supply Cooperative, Inc. ("WPSC") | Wolverine Transmission Ownership and Operating Agreement, dated 7/27/92 |
| 256[5] | METC | Michigan Public Power Agency ("MPPA") | Campbell Unit No. 3 Transmission Ownership and Operating Agreement, dated 10/1/79 |
| 257[5] | METC | Michigan Public Power | Belle River Transmission Ownership |

| | | | |
|---|---|---|---|
| | | Agency ("MPPA") | and Operating Agreement, dated |
| | | | 12/1/82 |

| GFA No. | Transmission Owner | Customer Name | Contract Title |
|---|---|---|---|
| 266[5] and | METC | Michigan South Central Power Agency ("MSCPA") | Project I Transmission Ownership Operating Agreement, dated 11/20/80 |

| | | | |
|---|---|---|---|
| 267[5] | METC | Consumers Power Company and the Detroit Edison Company | Ludington Project Transmission Facilities Agreement, dated 8/20/69 |
| 268[5] | METC | Consumers Power Company and the Detroit Edison Company | Transmission Facilities Agreement, dated 8/20/69 |
| 269[5] | METC | Consumers Power Company and the | Ludington Pumped Storage Plant Ownership and Operating |

| | | | |
|---|---|---|---|
| | | Detroit Edison | Agreements, dated 8/20/69 |
| | | Company | |
| 293 | Northwestern | Dairyland Power | Interconnection and Facility Use |
| | Wisconsin Elec. | Cooperative | Agreement, dated 9/16/83 |

| GFA No. | Transmission Owner | Customer Name | Contract Title |
|---|---|---|---|
| 308 | Otter Tail Power | East River Electric Power | Interconnection and Transmission |
| | Company | Cooperative, Inc. | Service Agreement |

| | | | |
|---|---|---|---|
| 321 | Otter Tail Power Company | Mountrail Electric Cooperative, Inc. | Interconnection Agreement between Mountrail Electric Cooperative, Inc. and Otter Tail Power Company |
| 360 | Xcel Energy – Northern States Power Company | City of Sioux Falls, SD | Municipal Interconnection & Interchange Agreement |
| 364 | Xcel Energy – Northern States | University of North Dakota | Transmission and Transformation Agreement |

| | | | |
|---|---|---|---|
| | Power Company | | |
| 365 | Xcel Energy – | City of Granite Falls, MN | Transmission Service Agreement |
| | Northern States | | |
| | Power Company | | |
| 389 | Xcel Energy – | East River Electric | Transmission Service Exchange |
| | Northern States | Cooperative | Agreement |
| | Power Company | | |
| **GFA** | **Transmission** | **Customer** | **Contract** |
| **No.** | **Owner** | **Name** | **Title** |

| | | | |
|---|---|---|---|
| 391 | Xcel Energy – Northern States Power Company | East River Electric Power Cooperative, Inc. (formerly Renville/Sibley Cooperative Power Association) | Transmission Service Agreement, dated 10/1/66 |
| 394 | Alliant Energy – Interstate Power and Light Company | MidAmerican Energy Co. | Interconnection, Interchange, and Joint Construction Agreement |
| 410[6] | American Transmission | City of Cleveland, OH | FERC Electric Tariff Original Volume No. 1 of the Cleveland |

| | | | |
|---|---|---|---|
| | System, Inc. | | Electric Illuminating Company |
| 415 | American | City of Cleveland, OH | FERC Electric Tariff |
| Original | | | |
| | Transmission | | Volume No. 1 of the Cleveland |
| | System, Inc. | | Electric Illuminating Company |
| 416[7] | Northern Indiana | Wabash Valley Power | Interconnection Agreement |
| | Public Service | Association, Inc. | |
| | Company | | |
| **GFA** | **Transmission** | **Customer** | **Contract** |

| No. | Owner | Name | Title |
|---|---|---|---|
| 421[8] | Michigan Public Power Agency | | |
| 422[9] | Michigan Public Power Agency | | |
| 423 | Michigan Public Power Agency | | |
| 424 | Michigan Public | | |

| | | | |
|---|---|---|---|
| | Power Agency | | |
| 428[10] | Northern Indiana Public Service Company | Wabash Valley Power Association, Inc. | Interconnection Agreement |
| 431 | Xcel Energy – Northern States Power Company | Water, Light, Power, & Building Commission of and for the City of East Grand Forks | Transmission Facilities Agreement |

**ATTACHMENT 2**

FORM OF SCHEDULE 23 SERVICE AGREEMENT

1.0 This Schedule 23 Service Agreement ("Service Agreement"), dated as of ____________________, is entered into, by and between the Midcontinent Independent System Operator, Inc., ("Transmission Provider") and________________________ ("Carved-Out GFA Customer").

2.0 The Carved-Out GFA Customer has been determined by the Transmission Provider to be a Carved-Out GFA Customer as set forth in Schedule 23 and Attachment 1 to Schedule 23 of the Tariff.

3.0 The Carved-Out GFA Customer agrees to provide to the Transmission Provider a completed Section II, pages 1 and 2, to the Market Participant registration packet, along with electronic banking instructions, NERC ID and the Carved-Out GFA Customer's DUNs number, in order to implement this Schedule 23.

4.0 The Transmission Provider agrees to provide services to the Carved-Out GFA Customer pursuant to Schedule 10, Schedule 17 and Schedule 23 of this Tariff. The Carved-Out GFA Customer agrees to take and pay for the requested services in accordance with the provisions of Section 38.8.4 of the Tariff[31] (and other provisions specifically referenced therein) and this Service Agreement.

5.0 This Service Agreement shall terminate upon termination of the Carved-Out GFA for which these Schedule 23 charges are being assessed in accordance with any applicable Commission rules. Such termination of this Service Agreement does not absolve the Carved-Out GFA customer from payment of outstanding obligations under this Service Agreement.

6.0 The Carved-Out GFA Customer shall provide written notification of any unexpected material adverse changes in circumstances that may affect the Carved-Out GFA Customer's status as a Carved-Out GFA Customer, within twenty-four (24) hours of having learned of the change.

7.0 All payments due under this Schedule 23 – Attachment 2 shall be made pursuant to the Billing and Payment procedures specified in Sections 7.3 and 7.11 through 7.18 of this Tariff except that these sections do not apply to the extent they refer to the Billing and Payment provisions of this Tariff other than sections 7.3 and 7.11 through 7.18.

8.0 Any notice or request made to either of the parties to this Service Agreement shall be made to the following representatives:

| Transmission Provider | Carved-Out GFA Customer |
|---|---|
| Title: Contract Administrator | ____________________ |
| Address: 701 City Center Drive | ____________________ |

Carmel, IN 46032 ______________________

9.0 Section 38.8.4 of the Tariff (and other provisions specifically referenced therein) is incorporated herein and made a part hereof.

IN WITNESS WHEREOF, the parties have caused this Service Agreement to be executed by their respective authorized officials.

| Transmission Provider | Carved-Out GFA Customer |
|---|---|
| By: ______________ | By: ______________ |
| Name: ______________ | Name: ______________ |
| Title: ______________ | Title: ______________ |
| Date: ______________ | Date: ______________ |

1 GFA No. 14 includes Schedule 10 costs. Therefore, for this GFA, the cost recovery only applies to Schedule 17 costs.

2 At the present time, Alliant Energy and Central Iowa Power Cooperative ("CIPCO") operate a joint dispatch pool under the IE/CIPCO Operating and Transmission Agreement ("O&T Agreement"). MISO charges incurred due to the CIPCO load is currently billed by Alliant Energy, by mutual agreement, under the O&T Agreement. Therefore, for GFA Nos. 16, 28, 29, 30, 31, 35, and 36, no direct billing of CIPCO, by MISO, for Schedules 10 and 17 should occur until such time as MISO is notified in writing by Alliant Energy.

3 Alliant Energy – Interstate Power and Light Company is responsible for Schedule 23 charges for the Corn Belt load served from the Alliant Energy – Interstate Power and Light Company under GFA No. 17.

4 This GFA is subject to proceedings in Docket No. ER02-2560, in which LG&E has requested cost recovery of Schedule 10 and 17 charges. LG&E lists this GFA here in the event that the Commission denies recovery in Docket No. ER02-2560. No final order has been issued in this proceeding at this time.

5 In *Midwest Independent Transmission System Operator, Inc.*, 111 FERC ¶ 61,042 at P 150 (2005), the Commission held that Michigan Electric Transmission Company, LLC ("METC"), is not responsible for Transmission Provider charges assessed to Carved-Out GFAs; rather, the Commission held that the Customers under these contracts are to be held directly responsible. Accordingly, provisions in Schedule 23 that are inconsistent with the Order are inapplicable to METC, including those in Section 2.2 that require Transmission Owners to remain responsible for Schedule 10 and 17 charges if not paid by Carved-Out GFA Customers within the remittance requirements set forth in Section 7 of the Energy Markets Tariff. Therefore, for GFA Nos. 254, 255, 256, 257, 266, 267, 268, and 269, no charges should be billed by MISO to METC.

6 This Schedule 23 shall not apply to out-of-pocket costs of excess of sheet 4, section D of this contract to the extent that such out-of-pocket costs for excess already include Schedule 10 and Schedule 17 costs.

7 GFA Nos. 416 and 428 are the same contract.

8 GFA Nos. 421 and 257 are the same contract.

9 GFA Nos. 422 and 256 are the same contract.

10 GFA No. 428 and 416 are the same contract.

[11] *See, Midwest Independent Transmission Operator, Inc.* 111 FERC ¶ 61,042 (2005); *Midwest Independent Transmission System Operator, Inc.* 108 FERC ¶ 61,236 (2004).

**Item 10) Refer to the Direct Testimony of Christopher Heimgartner (Heimgartner Testimony), pages 20-21, regarding the extent of Henderson's obligation to share in decommissioning costs.**

**a. State whether Henderson disputes BREC's contention that additional ongoing expenses will be incurred indefinitely if additional actions are not taken to decommission Station Two, and explain each basis for your response.**

**b. Explain how Henderson contends that the term "decommissioning," as used in the 1993 Amendment to the contracts that requires Henderson and BREC to share in the "decommissioning costs," should be defined, and explain each basis for Henderson's contention as to the meaning of decommissioning.**

**c. State whether Henderson contends that its ownership of the property on which Station Two is located while Station Two was operating had any bearing on BREC's obligations to cover its share of the operation and maintenance expenses for Station Two.**

**d. Explain each basis for Henderson's contention that the transfer of the title of the property on which Station Two is located would have any bearing on the obligation in the 1993 Amendment to the contracts that "the parties shall bear decommissioning costs of Station Two in the proportions in which they shared capacity costs during the life of Station Two."**

**Response)** a. BREC witness Jeffrey T. Kopp states in his direct testimony (Kopp Testimony) that retirement in place will result in "carrying costs." Henderson does not dispute that "carrying costs" such as those described in the Kopp Testimony could be incurred.

b. The term "decommissioning" is not defined in the Station Two contracts. To the best of Henderson's knowledge, the power industry also does not provide a single definition that requires specific activities on a specific timeline to be applied in every case. The Kopp Testimony acknowledges the existence of at least three options, all of which constitute decommissioning. One of those options is retirement in place, which is accomplished when a generating plant ceases operation and is brought to "safe, dark, and dry" status. This occurred with respect to Station Two no later than May 1, 2019. Henderson's position is that decommissioning was complete at that time and that Henderson's share of decommissioning costs is limited to those costs incurred between February 1, 2019 (the date the plant ceased operation) and May 1, 2019.

c. BREC's obligation to pay its share of operating and maintenance expenses during the life of Station Two arose from the Station Two contracts, which did not address the ownership of the land.

d. Henderson does not so contend. Title to the Station Two property reverted to Big Rivers under the terms of the pertinent Deed. Henderson fulfilled its independent contractual obligation to pay its share of decommissioning costs when decommissioning was completed, on or before May 1, 2019.

**Witness) Chris Heimgartner**

**Item 11)** **Refer to the Heimgartner Testimony, page 21. State whether the Station Two Bonds have been retired, and if so, state when the last of the bonds was retired.**

**Response)** The bonds Mr. Heimgartner discusses in his testimony are those bonds issued for the construction and completion of the Station Two generating plant. These bonds are retired, with the final payment having been made on March 1, 2003. To ensure the completeness of its response, Henderson states that a portion of funds from one outstanding bond series were devoted to capital projects designed to ensure the ongoing operation of the plant. These projects were not related to the construction or completion of the plant. The bonds, issued by the City of Henderson, are known as the Series 2011A bonds in the amount of $11,350,000.

**Witness)** **Barbara Moll**

**Item 12) Refer to the Heimgartner Testimony, page 22, and BREC's Application Exhibit 14, pages 71-73 of 123. Explain why the amendment to Section 6.3 of the Power Sales Contract would not encompass severance costs.**

**Response)** Section 6.3(h) should not be treated as an all-purpose repository for any type of cost BREC decides to call an operating cost. The severance packages BREC elected to offer its employees are not operating costs and are not properly attributable to Station Two. BREC represented to Henderson that the closure of Station Two would have no negative impact on the workforce and that Big Rivers could absorb the reduction. BREC's suggestion that severance packages were necessary to keep a sufficient number of employees working at Station Two until operations ceased is based upon nothing more than speculation. BREC cites to no study or other authority to support its "opinion" and "belief" that employees assigned to Station Two would have abruptly quit between the time severance packages were offered on November 6, 2018, and the time the plant ceased operation on January 31, 2019.

**Witness) Chris Heimgartner**

**Item 13) Refer to the Heimgartner Testimony, pages 22-23, and the Direct Testimony of Barbara Moll (Moll Testimony), pages 9-10, regarding Henderson's use of and its obligation to cover the costs for BREC's landfill.**

**a. Explain each basis for Henderson's "understanding" that BREC has undertaken a three-phase expansion of its landfill that is expected to extend the life of the landfill by 20 years.**

**b. Explain each basis for Henderson's contention that costs it paid prior to the shutdown of Station Two were used to fund the expansion of the landfill.**

**c. Identify when Henderson first disputed each of the "unauthorized disposal charges" referred to on page 10 of the Moll testimony.**

**Response)** a. BREC stated in response to Item 56 of Henderson's First Request for Information that BREC had initiated a "multi-phase" vertical expansion to increase the storage capacity of its landfill by approximately 15 years (BREC witness Michael T. Pullen states on p. 18 of his direct testimony (Pullen Testimony) that the landfill has approximately 20 years of remaining life, assuming the completion of the expansion continues as currently planned.). BREC further indicated in its response that BREC would complete the first of three phases in 2021. BREC did not cite to any study or other authority to support its determination that its landfill was nearing capacity and required a "multi-phase vertical expansion." Rather, BREC stated in response to Item 55 that BREC initiated the expansion in May 2015 based on nothing more than BREC's estimation that the landfill would be full and unable to accept additional waste by the end of 2017. BREC has not even confirmed that its estimate was correct or that its landfill was completely full prior to the date operations ceased at Station Two.

As explained on p. 22 of the Heimgartner Testimony, Henderson no longer has a contractual obligation to operate or maintain any joint-use facilities, including the Station Two ash-pond dredgings. Section 6.2 of the Joint Facilities Agreement obligates Henderson to share in the costs of operating and maintaining joint-use facilities, including the Station two ash-pond dredgings, "so as to assure the continuous operation of the parties' respective generating station or stations served thereby." Section 8.1 of the agreement states that this obligation remains in effect "so long as either party continues to operate or maintain a generating station which is served by any such joint-use facility." Neither party is currently operating or maintaining a generating station which is "served by" the Station Two ash-pond dredgings. Therefore, Henderson's obligation to operate and/or maintain the ash-pond dredgings has ceased.

Henderson has no interest in extending or obligation to extend the life of Big Rivers' landfill and will not voluntarily expend public funds to do so. Henderson compensated Big Rivers in an appropriate sum to dispose of Henderson's share of the ash-pond dredgings attributable to Station Two.

b. As explained in the Moll Testimony, the proposed Station Two operating plan BREC submitted for fiscal 2015-2016 reflected a sharp increase in the per-ton disposal rate for ash-pond waste attributable to Station Two. Projected disposal costs for the next three fiscal years also were dramatically higher than the price the Henderson Utility Commission had approved (see attached sheets from the proposed Station Two operating plans BREC submitted for fiscal years 2014-2015 through 2016-2017). Big Rivers confirmed in its response to Item 66 of Henderson's First Request for Information that the increase was largely attributable to the landfill expansion (see documentation submitted with BREC response to Henderson Item 66).

c. Henderson initially questioned the unexplained increase in disposal costs when Henderson reviewed the proposed operating plan BREC submitted for fiscal 2015-2016. The earliest record of the dispute is contained in the attached spreadsheet of questions and answers the parties exchanged as part of the budget-approval process for fiscal 2015-2016. The earliest dated correspondence Henderson is able to locate reflecting its written objection to the increased disposal charges and MISO fees is a letter from HMP&L Power Supply Director Ken Brooks to BREC Chief Financial Officer Lindsay Durbin dated December 27, 2017 (see attached).

**Witness)** **Chris Heimgartner** 13(a)

**Barbara Moll** 13(b-c)

Henderson Station Two
2014 / 2015 Operating Plan
*Reagent Costs*

| | Jun '14 | Jul '14 | Aug '14 | Sep '14 | Oct '14 | Nov '14 | Dec '14 | Jan '15 | Feb '15 | Mar '15 | Apr '15 | May '15 | FYE 14/15 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| NET GENERATION (MWH) | | | | | | | | | | | | | |
| TATION TWO: | 188,568 | 196,665 | 196,138 | 187,180 | 194,837 | 187,260 | 192,728 | 196,127 | 184,792 | 194,576 | 184,793 | 119,184 | 2,222,849 |
| REC: | 132,577 | 139,545 | 135,912 | 136,175 | 150,207 | 144,102 | 146,566 | 141,394 | 128,632 | 144,705 | 142,436 | 79,779 | 1,622,033 |
| MP&L | 55,991 | 57,118 | 60,226 | 51,005 | 44,630 | 43,158 | 46,162 | 54,733 | 56,160 | 49,871 | 42,357 | 39,405 | 600,816 |
| djusted per HMP&L's Request | - | - | - | - | - | - | - | - | - | - | - | - | - |
| MP&L (Projected): | 55,991 | 57,118 | 60,226 | 51,005 | 44,630 | 43,158 | 46,162 | 54,733 | 56,160 | 49,871 | 42,357 | 39,405 | 600,816 |
| REEN: | 279,623 | 293,865 | 294,419 | 278,570 | 293,275 | 283,291 | 295,104 | 290,451 | 265,304 | 284,974 | 180,311 | 274,357 | 3,313,554 |
| DISPOSAL (TONS) | | | | | | | | | | | | | |
| TATION TWO: | | | | | | | | | | | | | |
| Pozatec/Ash Disposal - Flyash - Tons / Gross MWH | 0.1514 | 0.1514 | 0.2043 | 0.2177 | 0.1514 | 0.1514 | 0.1514 | 0.1514 | 0.1514 | 0.1514 | 0.1514 | 0.1514 | |
| Pozatec/Ash Disposal - Flyash - Tons of Disposal | 28,551 | 29,777 | 40,063 | 40,744 | 29,500 | 28,353 | 29,181 | 29,696 | 27,979 | 29,461 | 27,980 | 18,046 | 359,331 |
| Bottom Ash - Tons / Gross MWH | 0.0098 | 0.0098 | 0.0958 | 0.1177 | 0.0098 | 0.0098 | 0.0098 | 0.0098 | 0.0098 | 0.0098 | 0.0098 | 0.0098 | |
| Bottom Ash - Tons of Disposal | 1,845 | 1,924 | 18,794 | 22,022 | 1,906 | 1,832 | 1,885 | 1,919 | 1,808 | 1,904 | 1,808 | 1,166 | 58,813 |
| STATION TWO Gross Tons of Disposal | 30,396 | 31,701 | 58,857 | 62,766 | 31,406 | 30,185 | 31,066 | 31,615 | 29,787 | 31,365 | 29,788 | 19,212 | 418,144 |
| REC: | | | | | | | | | | | | | |
| Pozatec/Ash Disposal - Flyash - Tons / Gross MWH | 0.1514 | 0.1514 | 0.2043 | 0.2177 | 0.1514 | 0.1514 | 0.1514 | 0.1514 | 0.1514 | 0.1514 | 0.1514 | 0.1514 | |
| Pozatec/Ash Disposal - Flyash - Tons of Disposal | 20,073 | 21,129 | 27,761 | 29,642 | 22,743 | 21,818 | 22,192 | 21,409 | 19,476 | 21,910 | 21,567 | 12,080 | 261,800 |
| Bottom Ash - Tons / Gross MWH | 0.0098 | 0.0098 | 0.0958 | 0.1177 | 0.0098 | 0.0098 | 0.0098 | 0.0098 | 0.0098 | 0.0098 | 0.0098 | 0.0098 | |
| Bottom Ash - Tons of Disposal | 1,297 | 1,365 | 13,023 | 16,021 | 1,469 | 1,410 | 1,434 | 1,383 | 1,259 | 1,416 | 1,394 | 780 | 42,251 |
| BREC Gross Tons of Disposal | 21,370 | 22,494 | 40,784 | 45,663 | 24,212 | 23,228 | 23,626 | 22,792 | 20,735 | 23,326 | 22,961 | 12,860 | 304,051 |
| Landfill Pozatec/Ash Disposal - Flyash (per ton) | 1.780 | 1.780 | 1.780 | 1.780 | 1.780 | 1.780 | 1.780 | 1.780 | 1.780 | 1.780 | 1.780 | 1.780 | |
| Landfill Pozatec/Ash Disposal - Bottom Ash (per ton) | 1.780 | 1.780 | 1.780 | 1.780 | 1.780 | 1.780 | 1.780 | 1.780 | 1.780 | 1.780 | 1.780 | 1.780 | |
| REC DISPOSAL COSTS | 38,039 | 40,039 | 72,596 | 81,280 | 43,097 | 41,346 | 42,054 | 40,570 | 36,908 | 41,520 | 40,871 | 22,891 | 541,211 |
| IMP&L: | | | | | | | | | | | | | |
| Pozatec/Ash Disposal - Flyash - Tons / Gross MWH | 0.1514 | 0.1514 | 0.2043 | 0.2177 | 0.1514 | 0.1514 | 0.1514 | 0.1514 | 0.1514 | 0.1514 | 0.1514 | 0.1514 | |
| Pozatec/Ash Disposal - Flyash - Tons of Disposal | 8,478 | 8,648 | 12,302 | 11,102 | 6,757 | 6,535 | 6,989 | 8,287 | 8,503 | 7,551 | 6,413 | 5,966 | 97,531 |
| Bottom Ash - Tons / Gross MWH | 0.0098 | 0.0098 | 0.0958 | 0.1177 | 0.0098 | 0.0098 | 0.0098 | 0.0098 | 0.0098 | 0.0098 | 0.0098 | 0.0098 | |
| Bottom Ash - Tons of Disposal | 548 | 559 | 5,771 | 6,001 | 437 | 422 | 451 | 536 | 549 | 488 | 414 | 386 | 16,562 |
| HMP&L Gross Tons of Disposal | 9,026 | 9,207 | 18,073 | 17,103 | 7,194 | 6,957 | 7,440 | 8,823 | 9,052 | 8,039 | 6,827 | 6,352 | 114,093 |
| Landfill Pozatec/Ash Disposal - Flyash (per ton) | 1.780 | 1.780 | 1.780 | 1.780 | 1.780 | 1.780 | 1.780 | 1.780 | 1.780 | 1.780 | 1.780 | 1.780 | |
| Landfill Pozatec/Ash Disposal - Bottom Ash (per ton) | 1.780 | 1.780 | 1.780 | 1.780 | 1.780 | 1.780 | 1.780 | 1.780 | 1.780 | 1.780 | 1.780 | 1.780 | |
| Landfill (Pozatec/Ash Disposal) - HMPL Only | 16,066 | 16,388 | 32,170 | 30,443 | 12,805 | 12,383 | 13,243 | 15,705 | 16,113 | 14,309 | 12,152 | 11,307 | 203,084 |
| Landfill Usage Fee (per ton) - HMPL Only | 1.077 | 1.077 | 1.077 | 1.077 | 1.077 | 1.077 | 1.077 | 1.077 | 1.077 | 1.077 | 1.077 | 1.077 | |
| Landfill Usage Fee - HMPL Only | 9,721 | 9,916 | 19,465 | 18,420 | 7,748 | 7,493 | 8,013 | 9,502 | 9,749 | 8,658 | 7,353 | 6,841 | 122,879 |
| IMP&L DISPOSAL COSTS | 25,787 | 26,304 | 51,635 | 48,863 | 20,553 | 19,876 | 21,256 | 25,207 | 25,862 | 22,967 | 19,505 | 18,148 | 325,963 |

**Attachment 1 for Henderson's Response to Commission Staff 13(b)**

# Henderson Station Two
## 2014 / 2015 Operating Plan
### *Reagent Costs*

| | Jun '14 | Jul '14 | Aug '14 | Sep '14 | Oct '14 | Nov '14 | Dec '14 | Jan '15 | Feb '15 | Mar '15 | Apr '15 | May '15 | FYE 14/15 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **GREEN:** | | | Increased due to Landfill Capping | | | | | | | | | | |
| Pozatec/Ash Disposal - Flyash - Tons / Gross MWH | 0.1950 | 0.1950 | 0.1950 | 0.1950 | 0.1950 | 0.1950 | 0.1950 | 0.1950 | 0.1950 | 0.1950 | 0.1950 | 0.1950 | |
| Pozatec/Ash Disposal - Flyash - Tons of Disposal | 54,522 | 57,299 | 57,407 | 54,316 | 57,184 | 55,237 | 57,540 | 56,633 | 51,730 | 55,565 | 35,158 | 53,497 | 646,088 |
| Bottom Ash - Tons / Gross MWH | 0.0158 | 0.0158 | 0.0158 | 0.0158 | 0.0158 | 0.0158 | 0.0158 | 0.0158 | 0.0158 | 0.0158 | 0.0158 | 0.0158 | |
| Bottom Ash - Tons of Disposal | 4,430 | 4,656 | 4,664 | 4,413 | 4,646 | 4,488 | 4,675 | 4,602 | 4,203 | 4,515 | 2,857 | 4,347 | 52,496 |
| **GREEN Gross Tons of Disposal** | 58,952 | 61,955 | 62,071 | 58,729 | 61,830 | 59,725 | 62,215 | 61,235 | 55,933 | 60,080 | 38,015 | 57,844 | 698,584 |
| **STATION TWO & GREEN Gross Tons of Disposal** | 89,348 | 93,656 | 120,928 | 121,495 | 93,236 | 89,910 | 93,281 | 92,850 | 85,720 | 91,445 | 67,803 | 77,056 | 1,116,728 |
| Station II % of Total Site Disposal | 34.0% | 33.8% | 48.7% | 51.7% | 33.7% | 33.6% | 33.3% | 34.0% | 34.7% | 34.3% | 43.9% | 24.9% | |
| **FGD SYSTEM COST** | | | | | | | | | | | | | |
| **Shared FGD System - Disposal Allocation:** | | | | | | | | | | | | | |
| Fixation Lime - Green | $ 95,801 | $ 100,680 | $ 100,870 | $ 95,440 | $ 100,478 | $ 97,057 | $ 101,104 | $ 101,627 | $ 93,010 | $ 99,906 | $ 63,214 | $ 96,188 | $ 1,145,574 |
| Fixation Lime - SII | 47,641 | 49,687 | 49,554 | 47,290 | 49,225 | 47,311 | 48,692 | 50,704 | 47,774 | 50,303 | 47,774 | 30,812 | 566,767 |
| Ash Pond Dredging - SII | - | - | 52,500 | 52,500 | - | - | - | - | - | - | - | - | 105,000 |
| Sodium Bisulfite - Green | 4,004 | 4,208 | 4,216 | 3,989 | 4,199 | 4,056 | 4,225 | 4,159 | 3,799 | 4,080 | 2,582 | 3,929 | 47,445 |
| Sodium Bisulfite - SII | 2,700 | 2,816 | 2,808 | 2,680 | 2,790 | 2,681 | 2,760 | 2,808 | 2,646 | 2,766 | 2,646 | 1,707 | 31,828 |
| **Total Shared FGD System - Disposal Allocation** | 150,145 | 157,391 | 209,947 | 201,899 | 156,692 | 151,105 | 156,781 | 159,498 | 147,229 | 157,076 | 116,216 | 132,635 | 1,896,614 |
| Station II % of Total Site Disposal | 34.0% | 33.8% | 48.7% | 51.7% | 33.7% | 33.6% | 33.3% | 34.0% | 34.7% | 34.3% | 43.9% | 24.9% | |
| **STATION TWO Portion of Disposal** | $ 51,079 | $ 53,274 | $ 102,184 | $ 104,304 | $ 52,781 | $ 50,730 | $ 52,214 | $ 54,308 | $ 51,161 | $ 53,876 | $ 51,057 | $ 33,069 | $ 710,037 |
| **SCR/Scrubber Reagents:** | | | | | | | | | | | | | |
| Ammonia - SII | $ 71,722 | $ 74,802 | $ 74,601 | $ 71,194 | $ 74,106 | $ 71,224 | $ 73,304 | $ 77,543 | $ 73,062 | $ 76,930 | $ 73,062 | $ 47,122 | $ 858,674 |
| Emulsified Sulfur - SII | 7,763 | 8,131 | 8,121 | 7,762 | 8,060 | 7,728 | 8,065 | 8,295 | 7,514 | 8,218 | 7,951 | 5,449 | 93,057 |
| **STATION TWO SCR/Scrubber Reagents** | $ 79,485 | $ 82,933 | $ 82,722 | $ 78,956 | $ 82,166 | $ 78,953 | $ 81,369 | $ 85,839 | $ 80,576 | $ 85,148 | $ 81,013 | $ 52,571 | $ 951,731 |
| **Emission Controls: Air Emission Fees** | 28,274 | 29,748 | 29,413 | 28,743 | 28,877 | 29,011 | 29,279 | 32,571 | 32,032 | 32,494 | 32,340 | 30,569 | 363,351 |
| **FGD System Amortization** | 21,716 | 21,716 | 21,716 | 21,716 | 21,716 | 21,716 | 21,716 | 18,332 | 18,332 | 18,332 | 18,332 | 18,332 | 243,672 |
| **Total Station Two FGD System Cost** | $ 180,554 | $ 187,671 | $ 236,035 | $ 233,719 | $ 185,540 | $ 180,410 | $ 184,578 | $ 191,050 | $ 182,101 | $ 189,850 | $ 182,742 | $ 134,541 | $ 2,268,791 |
| **BREC FGD System Cost @ 197 MW** | $ 114,004 | $ 118,497 | $ 149,035 | $ 147,573 | $ 117,152 | $ 113,913 | $ 116,544 | $ 120,631 | $ 114,980 | $ 119,873 | $ 115,385 | $ 84,951 | $ 1,432,538 |
| **HMP&L FGD System Cost @ 115 MW** | $ 66,550 | $ 69,174 | $ 87,000 | $ 86,146 | $ 68,388 | $ 66,497 | $ 68,034 | $ 70,419 | $ 67,121 | $ 69,977 | $ 67,357 | $ 49,590 | $ 836,253 |
| **TOTAL FGD SYSTEM & DISPOSAL COST** | | | | | | | | | | | | | |
| **Total Station Two Reagent Costs** | $ 244,380 | $ 254,014 | $ 360,266 | $ 363,862 | $ 249,190 | $ 241,632 | $ 247,888 | $ 256,827 | $ 244,871 | $ 254,337 | $ 243,118 | $ 175,580 | $ 3,135,965 |
| **BREC Allocation of Reagent Costs** | $ 152,043 | $ 158,536 | $ 221,631 | $ 228,853 | $ 160,249 | $ 155,259 | $ 158,598 | $ 161,201 | $ 151,888 | $ 161,393 | $ 156,256 | $ 107,842 | $ 1,973,749 |
| **HMP&L Allocation of Reagent Costs** | $ 92,337 | $ 95,478 | $ 138,635 | $ 135,009 | $ 88,941 | $ 86,373 | $ 89,290 | $ 95,626 | $ 92,983 | $ 92,944 | $ 86,862 | $ 67,738 | $ 1,162,216 |

# Henderson Station Two
## 2015 / 2016 Operating Plan
### *FGD System Costs*

| | | Jun '15 | Jul '15 | Aug '15 | Sep '15 | Oct '15 | Nov '15 | Dec '15 | Jan '16 | Feb '16 | Mar '16 | Apr '16 | May '16 | FYE 15/16 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | NET GENERATION (MWH) | | | | | | | | | |
| STATION TWO: | | 191,378 | 199,675 | 198,559 | 189,476 | 194,101 | 185,352 | 198,325 | 213,773 | 200,650 | 198,531 | 185,800 | 120,766 | 2,276,386 |
| BREC: | | 134,478 | 142,851 | 138,204 | 137,287 | 145,925 | 140,106 | 148,112 | 159,482 | 151,311 | 150,344 | 139,593 | 71,476 | 1,659,171 |
| HMP&L | | 56,900 | 56,824 | 60,355 | 52,189 | 48,176 | 45,246 | 50,213 | 54,291 | 49,339 | 48,187 | 46,207 | 49,285 | 617,215 |
| GREEN: | | 276,405 | 290,932 | 289,180 | 216,615 | 138,340 | 237,233 | 290,148 | 326,649 | 305,623 | 303,856 | 280,672 | 294,773 | 3,256,426 |
| | | | | | DISPOSAL (TONS) | | | | | | | | | |
| STATION TWO: | | | | | | | | | | | | | | |
| Pozatec/Ash Disposal - Flyash - Tons / Gross MWH | | 0.1454 | 0.1454 | 0.1454 | 0.1454 | 0.1454 | 0.1454 | 0.1454 | 0.1448 | 0.1448 | 0.1448 | 0.1448 | 0.1448 | |
| Pozatec/Ash Disposal - Flyash - Tons of Disposal | | 27,835 | 29,042 | 28,879 | 27,558 | 28,231 | 26,959 | 28,845 | 30,948 | 29,048 | 28,741 | 26,898 | 17,483 | 330,467 |
| Bottom Ash - Tons / Gross MWH | | 0.0091 | 0.0091 | 0.0092 | 0.0092 | 0.0091 | 0.0092 | 0.0092 | 0.0091 | 0.0091 | 0.0091 | 0.0091 | 0.0091 | |
| Bottom Ash - Tons of Disposal | | 1,751 | 1,827 | 1,817 | 1,734 | 1,776 | 1,696 | 1,815 | 1,947 | 1,828 | 1,808 | 1,692 | 1,100 | 20,791 |
| STATION TWO Gross Tons of Disposal | | 29,586 | 30,869 | 30,696 | 29,292 | 30,007 | 28,655 | 30,660 | 32,895 | 30,876 | 30,549 | 28,590 | 18,583 | 351,258 |
| BREC: | | | | | | | | | | | | | | |
| Pozatec/Ash Disposal - Flyash - Tons / Gross MWH | | 0.1454 | 0.1454 | 0.1454 | 0.1454 | 0.1454 | 0.1454 | 0.1454 | 0.1448 | 0.1448 | 0.1448 | 0.1448 | 0.1448 | |
| Pozatec/Ash Disposal - Flyash - Tons of Disposal | | 19,559 | 20,777 | 20,101 | 19,967 | 21,234 | 20,378 | 21,542 | 23,088 | 21,905 | 21,765 | 20,209 | 10,348 | 240,863 |
| Bottom Ash - Tons / Gross MWH | | 0.0091 | 0.0091 | 0.0092 | 0.0092 | 0.0091 | 0.0092 | 0.0092 | 0.0091 | 0.0091 | 0.0091 | 0.0091 | 0.0091 | |
| Bottom Ash - Tons of Disposal | | 1,230 | 1,307 | 1,265 | 1,256 | 1,325 | 1,282 | 1,355 | 1,453 | 1,379 | 1,369 | 1,271 | 651 | 15,153 |
| BREC Gross Tons of Disposal | | 20,789 | 22,084 | 21,366 | 21,223 | 22,559 | 21,660 | 22,897 | 24,541 | 23,284 | 23,134 | 21,480 | 10,999 | 256,016 |
| Landfill Pozatec/Ash Disposal - Flyash (per ton) | $ | 5.610 | $ 5.610 | $ 5.610 | $ 5.610 | $ 5.610 | $ 5.610 | $ 5.610 | $ 5.610 | $ 5.610 | $ 5.610 | $ 5.610 | $ 5.610 | |
| Landfill Pozatec/Ash Disposal - Bottom Ash (per ton) | $ | 5.610 | $ 5.610 | $ 5.610 | $ 5.610 | $ 5.610 | $ 5.610 | $ 5.610 | $ 5.610 | $ 5.610 | $ 5.610 | $ 5.610 | $ 5.610 | |
| BREC DISPOSAL COSTS | $ | 116,626 | $ 123,891 | $ 119,863 | $ 119,061 | $ 126,556 | $ 121,613 | $ 128,452 | $ 137,676 | $ 130,623 | $ 129,782 | $ 120,503 | $ 61,704 | $ 1,436,249 |
| HMP&L: | | | | | | | | | | | | | | |
| Pozatec/Ash Disposal - Flyash - Tons / Gross MWH | | 0.1454 | 0.1454 | 0.1454 | 0.1454 | 0.1454 | 0.1454 | 0.1454 | 0.1448 | 0.1448 | 0.1448 | 0.1448 | 0.1448 | |
| Pozatec/Ash Disposal - Flyash - Tons of Disposal | | 8,276 | 8,265 | 8,778 | 7,591 | 7,007 | 6,581 | 7,303 | 7,860 | 7,143 | 6,976 | 6,689 | 7,135 | 89,604 |
| Bottom Ash - Tons / Gross MWH | | 0.0091 | 0.0091 | 0.0092 | 0.0092 | 0.0091 | 0.0092 | 0.0092 | 0.0091 | 0.0091 | 0.0091 | 0.0091 | 0.0091 | |
| Bottom Ash - Tons of Disposal | | 521 | 520 | 552 | 478 | 441 | 414 | 460 | 494 | 449 | 439 | 421 | 449 | 5,638 |
| HMP&L Gross Tons of Disposal | | 8,797 | 8,785 | 9,330 | 8,069 | 7,448 | 6,995 | 7,763 | 8,354 | 7,592 | 7,415 | 7,110 | 7,584 | 95,242 |
| Landfill Pozatec/Ash Disposal - Flyash (per ton) | $ | 5.610 | $ 5.610 | $ 5.610 | $ 5.610 | $ 5.610 | $ 5.610 | $ 5.610 | $ 5.610 | $ 5.610 | $ 5.610 | $ 5.610 | $ 5.610 | |
| Landfill Pozatec/Ash Disposal - Bottom Ash (per ton) | $ | 5.610 | $ 5.610 | $ 5.610 | $ 5.610 | $ 5.610 | $ 5.610 | $ 5.610 | $ 5.610 | $ 5.610 | $ 5.610 | $ 5.610 | $ 5.610 | |
| Landfill (Pozatec/Ash Disposal) - HMPL Only | $ | 49,351 | $ 49,284 | $ 52,341 | $ 45,267 | $ 41,783 | $ 39,242 | $ 43,550 | $ 46,866 | $ 42,591 | $ 41,598 | $ 39,887 | $ 42,546 | $ 534,306 |
| Landfill Usage Fee (per ton) - HMPL Only | $ | 1.077 | $ 1.077 | $ 1.077 | $ 1.077 | $ 1.077 | $ 1.077 | $ 1.077 | $ 1.077 | $ 1.077 | $ 1.077 | $ 1.077 | $ 1.077 | |
| Landfill Usage Fee - HMPL Only | $ | 9,474 | $ 9,451 | $ 10,048 | $ 8,690 | $ 8,021 | $ 7,534 | $ 8,361 | $ 8,997 | $ 8,177 | $ 7,986 | $ 7,657 | $ 8,168 | $ 102,574 |
| HMP&L DISPOSAL COSTS | $ | 58,825 | $ 58,745 | $ 62,389 | $ 53,957 | $ 49,804 | $ 46,776 | $ 51,911 | $ 55,863 | $ 50,768 | $ 49,584 | $ 47,544 | $ 50,714 | $ 636,880 |
| Station Two DISPOSAL COSTS | $ | 175,451 | $ 182,636 | $ 182,252 | $ 173,018 | $ 176,360 | $ 168,289 | $ 180,363 | $ 193,539 | $ 181,391 | $ 179,366 | $ 168,047 | $ 112,418 | $ 2,073,129 |

## Henderson Station Two
## 2015 / 2016 Operating Plan
### *FGD System Costs*

| | Jun '15 | Jul '15 | Aug '15 | Sep '15 | Oct '15 | Nov '15 | Dec '15 | Jan '16 | Feb '16 | Mar '16 | Apr '16 | May '16 | FYE 15/16 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **GREEN:** | | | | | | | | | | | | | |
| Pozzolanic/Ash Disposal - Flyash - Tons / Gross MWH | 0.1546 | 0.1546 | 0.1545 | 0.1546 | 0.1546 | 0.1546 | 0.1546 | 0.1539 | 0.1539 | 0.1539 | 0.1539 | 0.1539 | |
| Pozzolanic/Ash Disposal - Flyash - Tons of Disposal | 42,732 | 44,978 | 44,707 | 33,798 | 21,387 | 36,676 | 44,857 | 50,270 | 47,034 | 46,763 | 44,118 | 45,365 | 502,685 |
| Bottom Ash - Tons / Gross MWH | 0.0096 | 0.0096 | 0.0096 | 0.0096 | 0.0096 | 0.0096 | 0.0096 | 0.0095 | 0.0095 | 0.0095 | 0.0095 | 0.0095 | |
| Bottom Ash - Tons of Disposal | 2,650 | 2,790 | 2,773 | 2,096 | 1,327 | 2,275 | 2,782 | 3,118 | 2,917 | 2,901 | 2,737 | 2,814 | 31,180 |
| GREEN Gross Tons of Disposal | 45,382 | 47,768 | 47,480 | 35,894 | 22,714 | 38,951 | 47,639 | 53,388 | 49,951 | 49,664 | 46,855 | 48,179 | 533,865 |
| STATION TWO & GREEN Gross Tons of Disposal | 74,966 | 78,637 | 78,176 | 65,186 | 52,721 | 67,606 | 78,299 | 86,283 | 80,827 | 80,213 | 75,445 | 66,762 | 865,123 |
| Station II % of Total Site Disposal | 39.5% | 39.3% | 39.3% | 44.9% | 56.5% | 42.4% | 39.2% | 38.1% | 38.2% | 38.1% | 37.9% | 27.8% | |
| **FGD SYSTEM COST** | | | | | | | | | | | | | |
| Shared FGD System - Disposal Allocation: | | | | | | | | | | | | | |
| Fixation Lime - Green | $ 97,206 | $ 102,315 | $ 101,699 | $ 76,883 | $ 48,651 | $ 83,430 | $ 102,039 | $ 114,876 | $ 107,481 | $ 106,861 | $ 100,817 | $ 103,666 | $ 1,145,924 |
| Fixation Lime - SII | 67,304 | 70,222 | 69,629 | 66,635 | 68,261 | 65,185 | 69,747 | 75,180 | 70,554 | 69,819 | 66,342 | 42,471 | 800,559 |
| Ash Pond Dredging - SII | - | - | 52,500 | 52,500 | - | - | - | - | - | - | - | - | 105,000 |
| Sodium Bisulfite - Green | 3,551 | 3,730 | 3,715 | 2,809 | 1,777 | 3,049 | 3,728 | 4,197 | 3,927 | 3,904 | 3,683 | 3,787 | 41,864 |
| Sodium Bisulfite - SII | 2,459 | 2,565 | 2,551 | 2,434 | 2,494 | 2,381 | 2,548 | 2,747 | 2,576 | 2,551 | 2,367 | 1,552 | 29,247 |
| Subtotal Shared FGD System - Disposal Alloc | 170,520 | 178,840 | 230,294 | 201,261 | 121,184 | 154,044 | 178,062 | 196,999 | 184,550 | 183,135 | 172,229 | 151,476 | 2,122,594 |
| Station II % of Total Site Disposal | 39.5% | 39.3% | 39.3% | 44.9% | 56.9% | 42.4% | 39.2% | 38.1% | 38.2% | 38.1% | 37.9% | 27.8% | |
| STATION TWO Portion of Disposal | $ 67,295 | $ 70,204 | $ 90,426 | $ 90,439 | $ 68,974 | $ 65,292 | $ 69,725 | $ 75,105 | $ 70,498 | $ 69,747 | $ 65,267 | $ 42,163 | $ 845,135 |
| SCR/Scrubber Reagents: | | | | | | | | | | | | | |
| Ammonia - SII | $ 80,953 | $ 84,462 | $ 83,990 | $ 80,148 | $ 82,105 | $ 78,404 | $ 83,891 | $ 90,426 | $ 84,875 | $ 83,979 | $ 78,593 | $ 51,084 | $ 962,911 |
| Emulsified Sulfur - SII | 9,387 | 9,794 | 9,739 | 9,294 | 9,521 | 9,092 | 9,728 | 10,486 | 9,842 | 9,738 | 9,113 | 5,924 | 111,657 |
| STATION TWO SCR/Scrubber Reagents | $ 90,340 | $ 94,256 | $ 93,730 | $ 89,442 | $ 91,625 | $ 87,495 | $ 93,619 | $ 100,911 | $ 94,717 | $ 93,716 | $ 87,707 | $ 57,008 | $ 1,074,567 |
| Emission Controls: Air Emission Fees | 29,345 | 29,345 | 29,345 | 29,345 | 29,345 | 29,345 | 29,345 | 33,717 | 33,717 | 33,717 | 33,717 | 33,717 | 374,804 |
| FGD System Amortization | 18,332 | 18,332 | 18,332 | 18,332 | 18,332 | 18,332 | 18,332 | 14,947 | 14,947 | 14,947 | 14,947 | 14,947 | 203,059 |
| Total Station Two FGD System Cost | $ 205,312 | $ 212,136 | $ 231,833 | $ 227,559 | $ 208,277 | $ 200,465 | $ 211,022 | $ 224,681 | $ 213,879 | $ 212,128 | $ 201,638 | $ 147,835 | $ 2,496,765 |
| BREC FGD System Cost @ 197 MW | $ 129,636 | $ 133,946 | $ 146,382 | $ 143,683 | $ 131,508 | $ 126,576 | $ 133,241 | $ 141,866 | $ 135,045 | $ 133,940 | $ 127,316 | $ 93,345 | $ 1,576,484 |
| HMP&L FGD System Cost @ 115 MW | $ 75,676 | $ 78,192 | $ 85,451 | $ 83,876 | $ 76,769 | $ 73,889 | $ 77,781 | $ 82,815 | $ 78,834 | $ 78,188 | $ 74,322 | $ 54,490 | $ 920,283 |
| **TOTAL FGD SYSTEM & DISPOSAL COST** | | | | | | | | | | | | | |
| Total Station Two Reagent Costs | $ 380,763 | $ 394,774 | $ 414,085 | $ 400,577 | $ 384,637 | $ 368,754 | $ 391,385 | $ 418,219 | $ 395,278 | $ 391,494 | $ 369,685 | $ 260,253 | $ 4,569,896 |
| BREC Allocation of Reagent Costs | $ 246,262 | $ 257,837 | $ 266,245 | $ 262,744 | $ 258,064 | $ 248,089 | $ 261,693 | $ 279,541 | $ 265,668 | $ 263,722 | $ 247,819 | $ 155,049 | $ 3,012,733 |
| HMP&L Allocation of Reagent Costs | $ 134,501 | $ 136,937 | $ 147,840 | $ 137,833 | $ 126,573 | $ 120,665 | $ 129,692 | $ 138,678 | $ 129,602 | $ 127,772 | $ 121,866 | $ 105,204 | $ 1,557,163 |



U:\HMPL STATION TWO\HMPL BUDGET\2015\2016\HMPL BUDGET\2016 MODEL\Operating Plan.xlsx

# Henderson Station Two
## 2016 / 2017 Operating Plan
### *FGD System Costs*

| | Jun '16 | Jul '16 | Aug '16 | Sep '16 | Oct '16 | Nov '16 | Dec '16 | Jan '17 | Feb '17 | Mar '17 | Apr '17 | May '17 | FYE 16/17 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | NET GENERATION (MWH) | | | | | | | | | |
| **STATION TWO:** | 185,982 | 193,569 | 191,451 | 183,270 | 189,656 | 181,739 | 188,302 | 210,419 | 182,436 | 197,386 | 119,134 | 195,288 | 2,218,632 |
| **BREC:** | 129,364 | 136,549 | 131,079 | 131,555 | 142,645 | 136,552 | 138,084 | 156,836 | 134,193 | 148,916 | 76,070 | 146,258 | 1,608,101 |
| **HMP&L** | 56,518 | 57,020 | 60,372 | 51,715 | 47,011 | 45,187 | 50,218 | 53,583 | 48,243 | 48,470 | 43,064 | 49,030 | 610,531 |
| **GREEN:** | 233,119 | 248,644 | 238,737 | 228,779 | 242,892 | 224,913 | 231,291 | 322,952 | 270,655 | 210,828 | 206,547 | 257,957 | 2,917,414 |
| | | | | DISPOSAL (TONS) | | | | | | | | | |
| **STATION TWO:** | | | | | | | | | | | | | |
| Pozatec/Ash Disposal - Flyash - Tons / Gross MWH | 0.1448 | 0.1448 | 0.1448 | 0.1448 | 0.1448 | 0.1448 | 0.1448 | 0.1447 | 0.1447 | 0.1447 | 0.1447 | 0.1447 | |
| Pozatec/Ash Disposal - Flyash - Tons of Disposal | 26,930 | 28,028 | 27,722 | 26,537 | 27,462 | 26,315 | 27,266 | 30,450 | 26,400 | 28,564 | 17,240 | 28,260 | 321,174 |
| Bottom Ash - Tons / Gross MWH | 0.0091 | 0.0091 | 0.0091 | 0.0091 | 0.0091 | 0.0091 | 0.0091 | 0.0090 | 0.0090 | 0.0090 | 0.0090 | 0.0090 | |
| Bottom Ash - Tons of Disposal | 1,684 | 1,753 | 1,734 | 1,660 | 1,718 | 1,646 | 1,705 | 1,901 | 1,646 | 1,783 | 1,076 | 1,764 | 20,072 |
| **STATION TWO Gross Tons of Disposal** | 28,614 | 29,781 | 29,456 | 28,197 | 29,180 | 27,961 | 28,971 | 32,351 | 28,046 | 30,347 | 18,316 | 30,024 | 341,246 |
| **BREC:** | | | | | | | | | | | | | |
| Pozatec/Ash Disposal - Flyash - Tons / Gross MWH | 0.1448 | 0.1448 | 0.1448 | 0.1448 | 0.1448 | 0.1448 | 0.1448 | 0.1447 | 0.1447 | 0.1447 | 0.1447 | 0.1447 | |
| Pozatec/Ash Disposal - Flyash - Tons of Disposal | 18,732 | 19,772 | 18,960 | 19,049 | 20,655 | 19,772 | 19,994 | 22,696 | 19,419 | 21,550 | 11,008 | 21,165 | 232,792 |
| Bottom Ash - Tons / Gross MWH | 0.0091 | 0.0091 | 0.0091 | 0.0091 | 0.0091 | 0.0091 | 0.0091 | 0.0090 | 0.0090 | 0.0090 | 0.0090 | 0.0090 | |
| Bottom Ash - Tons of Disposal | 1,171 | 1,237 | 1,167 | 1,192 | 1,292 | 1,237 | 1,250 | 1,417 | 1,212 | 1,345 | 687 | 1,321 | 14,548 |
| **BREC Gross Tons of Disposal** | 19,903 | 21,009 | 20,167 | 20,241 | 21,947 | 21,009 | 21,244 | 24,113 | 20,631 | 22,895 | 11,695 | 22,486 | 247,340 |
| Landfill Pozatec/Ash Disposal - Flyash (per ton) | $ 6.850 | $ 6.850 | $ 6.850 | $ 6.850 | $ 6.850 | $ 6.850 | $ 6.850 | $ 6.850 | $ 6.850 | $ 6.850 | $ 6.850 | $ 6.850 | |
| Landfill Pozatec/Ash Disposal - Bottom Ash (per ton) | $ 6.850 | $ 6.850 | $ 6.850 | $ 6.850 | $ 6.850 | $ 6.850 | $ 6.850 | $ 6.850 | $ 6.850 | $ 6.850 | $ 6.850 | $ 6.850 | |
| **BREC DISPOSAL COSTS** | $ 136,336 | $ 143,912 | $ 138,144 | $ 138,651 | $ 150,337 | $ 143,912 | $ 145,521 | $ 165,174 | $ 141,322 | $ 156,831 | $ 80,111 | $ 154,029 | $ 1,694,280 |
| **HMP&L:** | | | | | | | | | | | | | |
| Pozatec/Ash Disposal - Flyash - Tons / Gross MWH | 0.1448 | 0.1448 | 0.1448 | 0.1448 | 0.1448 | 0.1448 | 0.1448 | 0.1447 | 0.1447 | 0.1447 | 0.1447 | 0.1447 | |
| Pozatec/Ash Disposal - Flyash - Tons of Disposal | 8,198 | 8,256 | 8,742 | 7,488 | 6,807 | 6,543 | 7,272 | 7,754 | 6,981 | 7,014 | 6,232 | 7,095 | 88,382 |
| Bottom Ash - Tons / Gross MWH | 0.0091 | 0.0091 | 0.0091 | 0.0091 | 0.0091 | 0.0091 | 0.0091 | 0.0090 | 0.0090 | 0.0090 | 0.0090 | 0.0090 | |
| Bottom Ash - Tons of Disposal | 513 | 516 | 547 | 468 | 426 | 409 | 455 | 484 | 436 | 438 | 389 | 443 | 5,524 |
| **HMP&L Gross Tons of Disposal** | 8,711 | 8,772 | 9,289 | 7,956 | 7,233 | 6,952 | 7,727 | 8,238 | 7,417 | 7,452 | 6,621 | 7,538 | 93,906 |
| Landfill Pozatec/Ash Disposal - Flyash (per ton) | $ 6.850 | $ 6.850 | $ 6.850 | $ 6.850 | $ 6.850 | $ 6.850 | $ 6.850 | $ 6.850 | $ 6.850 | $ 6.850 | $ 6.850 | $ 6.850 | |
| Landfill Pozatec/Ash Disposal - Bottom Ash (per ton) | $ 6.850 | $ 6.850 | $ 6.850 | $ 6.850 | $ 6.850 | $ 6.850 | $ 6.850 | $ 6.850 | $ 6.850 | $ 6.850 | $ 6.850 | $ 6.850 | |
| **Landfill (Pozatec/Ash Disposal) - HMPL Only** | $ 59,670 | $ 60,088 | $ 63,630 | $ 54,499 | $ 49,546 | $ 47,621 | $ 52,930 | $ 56,430 | $ 50,606 | $ 51,046 | $ 45,354 | $ 51,635 | $ 643,255 |
| Landfill Usage Fee (per ton) - HMPL Only | $ 1.077 | $ 1.077 | $ 1.077 | $ 1.077 | $ 1.077 | $ 1.077 | $ 1.077 | $ 1.077 | $ 1.077 | $ 1.077 | $ 1.077 | $ 1.077 | |
| **Landfill Usage Fee - HMPL Only** | $ 9,382 | $ 9,447 | $ 10,004 | $ 8,569 | $ 7,790 | $ 7,487 | $ 8,322 | $ 8,872 | $ 7,988 | $ 8,026 | $ 7,131 | $ 8,118 | $ 101,136 |
| **HMP&L DISPOSAL COSTS** | $ 69,052 | $ 69,535 | $ 73,634 | $ 63,068 | $ 57,336 | $ 55,108 | $ 61,252 | $ 65,302 | $ 58,794 | $ 59,072 | $ 52,485 | $ 59,753 | $ 744,391 |
| Station Two **DISPOSAL COSTS** | $ 205,388 | $ 213,447 | $ 211,778 | $ 201,719 | $ 207,673 | $ 199,020 | $ 206,773 | $ 230,476 | $ 200,116 | $ 215,903 | $ 132,596 | $ 213,782 | $ 2,438,671 |

# Henderson Station Two
## 2016 / 2017 Operating Plan
### *FGD System Costs*

| | Jun '16 | Jul '16 | Aug '16 | Sep '16 | Oct '16 | Nov '16 | Dec '16 | Jan '17 | Feb '17 | Mar '17 | Apr '17 | May '17 | FYE 16/17 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **GREEN:** | | | | | | | | | | | | | |
| Pozalec/Ash Disposal - Flyash - Tons / Gross MWH | 0.1569 | 0.1569 | 0.1569 | 0.1569 | 0.1569 | 0.1569 | 0.1569 | 0.1545 | 0.1545 | 0.1545 | 0.1545 | 0.1545 | |
| Pozalec/Ash Disposal - Flyash - Tons of Disposal | 36,566 | 39,001 | 37,447 | 35,885 | 38,099 | 35,279 | 36,279 | 49,894 | 41,814 | 32,572 | 31,926 | 39,653 | 454,615 |
| Bottom Ash - Tons / Gross MWH | 0.0082 | 0.0082 | 0.0082 | 0.0082 | 0.0082 | 0.0082 | 0.0082 | 0.0082 | 0.0082 | 0.0082 | 0.0082 | 0.0082 | |
| Bottom Ash - Tons of Disposal | 1,904 | 2,030 | 1,950 | 1,868 | 1,963 | 1,837 | 1,889 | 2,653 | 2,224 | 1,732 | 1,698 | 2,119 | 23,887 |
| **GREEN Gross Tons of Disposal** | 38,470 | 41,031 | 39,397 | 37,753 | 40,062 | 37,116 | 38,168 | 52,547 | 44,038 | 34,304 | 33,624 | 41,972 | 478,502 |
| **STATION TWO & GREEN Gross Tons of Disposal** | 67,064 | 70,812 | 68,853 | 65,950 | 69,262 | 65,077 | 67,139 | 84,898 | 72,086 | 64,651 | 51,940 | 71,996 | 819,748 |
| Station II % of Total Site Disposal | 42.7% | 42.1% | 42.8% | 42.8% | 42.1% | 43.0% | 43.2% | 38.1% | 38.9% | 46.9% | 35.3% | 41.7% | |
| **FGD SYSTEM COST** | | | | | | | | | | | | | |
| Shared FGD System - Disposal Allocation: | | | | | | | | | | | | | |
| Fixation Lime - Green | $ 62,978 | $ 67,172 | $ 64,496 | $ 61,805 | $ 65,618 | $ 60,761 | $ 62,484 | $ 86,240 | $ 72,274 | $ 56,299 | $ 55,182 | $ 68,884 | $ 784,192 |
| Fixation Lime - SII | 47,989 | 49,947 | 49,400 | 47,289 | 48,937 | 46,894 | 48,586 | 54,246 | 47,032 | 50,666 | 30,713 | 50,345 | 572,266 |
| Ash Pond Dredging - SII | - | - | - | 52,500 | 52,500 | - | - | - | - | - | - | - | 105,000 |
| Sodium Bisulfite - Green | 2,471 | 2,636 | 2,531 | 2,425 | 2,575 | 2,364 | 2,452 | 3,423 | 2,869 | 2,235 | 2,190 | 2,734 | 30,923 |
| Sodium Bisulfite - SII | - | - | - | - | - | - | - | - | - | - | - | - | 0 |
| **Subtotal Shared FGD System - Disposal Alloc** | 113,438 | 119,754 | 116,426 | 164,020 | 169,630 | 110,039 | 113,523 | 143,909 | 122,175 | 109,419 | 88,085 | 121,963 | 1,492,382 |
| Station II % of Total Site Disposal | 42.7% | 42.1% | 42.8% | 42.8% | 42.1% | 43.0% | 43.2% | 38.1% | 38.9% | 46.9% | 35.3% | 41.7% | |
| **STATION TWO Portion of Disposal** | $ 48,366 | $ 50,364 | $ 49,808 | $ 70,127 | $ 71,465 | $ 47,279 | $ 48,986 | $ 54,838 | $ 47,537 | $ 51,361 | $ 31,062 | $ 50,861 | $ 622,074 |
| SCR/Scrubber Reagents: | | | | | | | | | | | | | |
| Ammonia - SII | $ 85,357 | $ 88,839 | $ 87,867 | $ 84,113 | $ 87,044 | $ 83,410 | $ 86,422 | $ 89,897 | $ 77,942 | $ 84,329 | $ 50,898 | $ 93,433 | $ 939,552 |
| Emulsified Sulfur - SII | 9,708 | 10,104 | 9,994 | 9,567 | 9,900 | 9,487 | 9,829 | 10,984 | 9,523 | 10,304 | 6,219 | 10,194 | 115,813 |
| **STATION TWO SCR/Scrubber Reagents** | $ 95,066 | $ 98,944 | $ 97,861 | $ 93,679 | $ 96,944 | $ 92,897 | $ 96,252 | $ 100,881 | $ 87,465 | $ 94,633 | $ 57,116 | $ 93,627 | $ 1,105,364 |
| **Emission Controls: Air Emission Fees** | 49,816 | 49,816 | 49,816 | 49,816 | 49,816 | 49,816 | 49,816 | 47,524 | 47,524 | 47,524 | 47,524 | 47,524 | 536,335 |
| **FGD System Amortization** | 14,947 | 14,947 | 14,947 | 14,947 | 14,947 | 14,947 | 14,947 | 11,563 | 11,563 | 11,563 | 11,563 | 11,563 | 162,444 |
| **Total Station Two FGD System Cost** | $ 208,215 | $ 214,071 | $ 212,432 | $ 228,570 | $ 233,172 | $ 204,939 | $ 210,001 | $ 214,806 | $ 194,090 | $ 205,081 | $ 147,266 | $ 203,575 | $ 2,476,217 |
| **BREC FGD System Cost @ 197 MW** | $ 131,469 | $ 135,167 | $ 134,132 | $ 144,321 | $ 147,227 | $ 129,401 | $ 132,597 | $ 135,631 | $ 122,550 | $ 129,490 | $ 92,985 | $ 128,539 | $ 1,563,509 |
| **HMP&L FGD System Cost @ 115 MW** | $ 76,746 | $ 78,904 | $ 78,300 | $ 84,249 | $ 85,945 | $ 75,538 | $ 77,404 | $ 79,175 | $ 71,540 | $ 75,591 | $ 54,281 | $ 75,036 | $ 912,709 |
| **TOTAL FGD SYSTEM & DISPOSAL COST** | | | | | | | | | | | | | |
| **Total Station Two Reagent Costs** | $ 413,603 | $ 427,518 | $ 424,210 | $ 430,289 | $ 440,845 | $ 403,959 | $ 416,774 | $ 445,282 | $ 394,206 | $ 420,984 | $ 279,862 | $ 417,357 | $ 4,914,889 |
| **BREC Allocation of Reagent Costs** | $ 267,805 | $ 279,079 | $ 272,276 | $ 282,972 | $ 297,564 | $ 273,313 | $ 278,118 | $ 300,805 | $ 263,672 | $ 286,321 | $ 173,096 | $ 282,568 | $ 3,257,789 |
| **HMP&L Allocation of Reagent Costs** | $ 145,798 | $ 148,439 | $ 151,934 | $ 147,317 | $ 143,281 | $ 130,646 | $ 138,656 | $ 144,477 | $ 130,334 | $ 134,663 | $ 106,766 | $ 134,789 | $ 1,657,100 |

## Henderson Station Two Operating Plan 2015/2016

### Comments and Questions

| Q# | Pg | #/Pg | Questions or Comments | Comment/Answer |
|---|---|---|---|---|
| 1 | n/a | 1 | HMP&L requests an updated list of all personell, (bargaining, non-bargaining, support positions, etc) that are allocated to Station Two. | Listing was sent to Ken Brooks 4/9/15. |
| 2 | 3 | 1 | **G&A Non Labor:** Why has this item increased by 100% from last year? | Same Question as page 15 - Should the Summary Pages be removed from the budget for less confusion? |
| 3 | 3 | 2 | **MISO Load Expense:** Please remove this item from the Henderson Station Two Operating Plan 2015/2016. | Big Rivers will submit HMPL a letter stating our position as done in previous years. |
| 4 | 3 | 3 | **MISO Transmission Charges:** Please remove this item from the Henderson Station Two Operating Plan 2015/2016. | Big Rivers will submit HMPL a letter stating our position as done in previous years. |
| 5 | 6 | 1 | **RTO Purchased Power (555):** Please remove this item from the Henderson Station Two Operating Plan 2015/2016. | Big Rivers will submit HMPL a letter stating our position as done in previous years. |
| 6 | 6 | 2 | **RTO Load Dispatching (561):** Please remove this item from the Henderson Station Two Operating Plan 2015/2016. | Big Rivers will submit HMPL a letter stating our position as done in previous years. |
| 7 | 6 | 3 | **RTO Regional Market Expenses (575):** Please remove this item from the Henderson Station Two Operating Plan 2015/2016. | Big Rivers will submit HMPL a letter stating our position as done in previous years. |
| 8 | 6 | 4 | **Total MISO Expenses:** Please remove this item from the Henderson Station Two Operating Plan 2015/2016. | Big Rivers will submit HMPL a letter stating our position as done in previous years. |
| 9 | 6 | 5 | **Administrative Supplies & Expenses (921):** Why has this item increased by 100% from last year? | Same Question as Q#33 on page 15 - Should the Summary Pages be removed from the budget for less confusion? |
| 10 | 9 | 1 | **Ops Steam (502):** Why has this item increased by 34% from last year? | See Pgs 22-23 to compare 502 FERC (4 projects) |
| 11 | 10 | 1 | **Mtce Electrical (513):** Why has this item increased by 75% from last year? | See Pgs 22-23 to compare 513 FERC (However, Boiler Insulation & Lagging should be 512) |
| 12 | 11 | 1 | **Landfill (Pozatec/Ash Disposal): - HMP&L Only:** Why has this item increased by 115% from last year? | Landfill operating and maintenance costs are expected to increase as the landfill reaches its horizontal limits and additional vertical placement of the waste will be required. |
| 13 | 11 | 2 | **HMP&L Landfill Pozatec/Ash Disposal - Flyash (per ton):** Why has this item increased from $1.78 to $4.59 from last year? | Landfill operating and maintenance costs are expected to increase as the landfill reaches its horizontal limits and additional vertical placement of the waste will be required. |
| 14 | 11 | 3 | **HMP&L Landfill Pozatec/Ash Disposal - Bottom Ash (per ton):** Why has this item increased from $1.78 to $4.59 from last year? | Landfill operating and maintenance costs are expected to increase as the landfill reaches its horizontal limits and additional vertical placement of the waste will be required. |
| 15-17 | 12 | 1 | **Emulsified - SII:** This item needs to be split G/SII per agreement. How many tons of sulfur have been purchased in the last 12 months? What was the total spend for the last 12 months? | (1) BREC does not agree with the suggested split. (2) Jan-Dec 2014 - 281.11 tons at $121,439.52 total = $432/ton |
| 18 | 12 | 2 | **Fixation Lime - SII:** What is the price per ton for fixation lime used in the proposed budget? | 2015 & 2016 = $109.90/ton |
| 19-21 | 12 | 3 | **Ammonia - SII:** What is the price per ton for ammonia used in the proposed budget? How many tons of ammonia have been purchased in the last 12 months? What was the total spend for the last 12 months? | (1) 2015 = $547.13/ton and 2016 = $548.33/ton (2) Jan-Dec 2014 - 1,618.32 tons at $988,38.81 = $610.78/ton |

**Attachment 1 for Henderson's Response to Commission Staff 13(c)**

# Henderson Station Two Operating Plan 2015/2016

## Comments and Questions

| Q# | Pg | #/Pg | Questions or Comments | Comment/Answer |
|---|---|---|---|---|
| 22 | 13 | 1 | **O&M Labor, Maintenance:** Why has this item increased by 33% from last year? | This line increased by 8% - Overall O&M Labor only increased 1% (Change in Burden Calculation) |
| 23 | 14 | 1 | **Administration & VP, Operations:** Why has this item increased by 30% from last year? | This line increased by 5% - Overall G&A increased only 3% (Change in Burden Calculation) |
| 24 | 14 | 2 | **Account & Finance:** Why has this item increased by 35% from last year? | This line increased by 8% - Overall G&A increased only 3% (Change in Burden Calculation) |
| 25 | 14 | 3 | **Information Technology:** Why has this item increased by 37% from last year? | This line increased by 10% - Overall G&A increased only 3% (Change in Burden Calculation) |
| 26 | 14 | 4 | **Payroll:** Why has this item increased by 32% from last year? | This line increased by 5% - Overall G&A increased only 3% (Change in Burden Calculation) |
| 27 | 14 | 5 | **BU - Sourcing & Materials:** Why has this item increased by 35% from last year? | This line increased by 11% - Overall G&A increased only 3% (Change in Burden Calculation) |
| 28 | 14 | 6 | **NERC Compliance - Generation:** Why has this item increased by 30% from last year? | This line increased by 5% - Overall G&A increased only 3% (Change in Burden Calculation) |
| 29 | 14 | 7 | **Total Station Two G&A Labor:** Why has this item increased by 27% from last year? | Overall G&A increased only 3% ($2.062m compared to $2.009m) |
| 30 | 15 | 1 | **Production and Support Staff:** Why has this item increased by 35% from last year? | Increased to more closely to match the typical expenses. |
| 31 | 15 | 2 | **Gov't Relations & Enterprise Risk Mgmt:** Why has this item increased by 137% from last year? | This increased primarily due to risk assessments. |
| 32 | 15 | 3 | **General Services:** Why has this item increased by 30% from last year? | Bldg & Ground Mtce increased due to aging buildings, equipment, and necessary grounds upkeep. |
| 33 | 15 | 4 | **Info Systems & Technology:** Why has this item increased by 358% from last year? | The Station Two G&A Agreement allows an IT capacity split of 10% for all except the IT Engineers/Analysts. The budgeted IT expenses are related to the entire company and are managed by those employees who have an 18% split. Section 4.1(c) of the Station Two G&A Agreement allows BREC to allocate Information System services. The previous 10% allocation was carried over from WKEC operations and NOT the BREC Station Two Agreement. BREC does not propose to retroactively collect the difference between the 18% and 10% splits on unsettled previous Station Two fiscal years, however, going forward we feel it is appropriate to charge the 18% capacity split. |
| 34 | 16 | 5 | **Total Station Two G&A Non Labor Expenses:** Why has this item increased by 100% from last year? | Total G&A NL Increased $543k and IT was $549k. See Q#33 for response. |
| 35 | 16 | 1 | **MISO Transmission Charges:** Please remove this item from the Henderson Station Two Operating Plan 2015/2016. | Same as Page 3 |
| 36 | 20 | 1 | **Administrative Supplies & Expense:** Why has this item increased by 45% from last year? | Good Question. Why? |
| 37 | 22 | 1 | **RGH Landfill Expansion:** HMP&L will not participate and request that the item be removed from the 2015/2016 Operating Plan. | This project will be removed from the budget. |

Henderson Station Two Operating Plan 2015/2016

Comments and Questions

| Q# | Pg | #/Pg | Questions or Comments | Comment/Answer |
|---|---|---|---|---|
| 38-39 | 22 | 2 | **RH - Misc Capital Projects:** How much of the current year's $100,000.00 was actually spent on misc. capital projects? HMP&L recommends that the $100,000.00 be reduced. | The budget for this project has been the same for several years and is always used. With costs increasing I would suggest this project increase based on inflation each year. |
| 40-41 | 22 | 3 | **RH - Misc Capital Valves:** How much of the current year's $100,000.00 was actually spent on misc. capital valves? HMP&L recommends that the $100,000.00 be reduced | The budget for this project has been the same for several years and is always used. With costs increasing I would suggest this project increase based on inflation each year. |
| 42-43 | 22 | 4 | **RH - Misc Conveyor Belts:** How much of the current year's $90,000.00 was actually spent on misc. conveyor belts? HMP&L recommends that the $90,000.00 be reduced. | The budget for this project has been the same for several years and is always used. With costs increasing I would suggest this project increase based on inflation each year. |
| | | | | |
| 44-48 | 23 | 1 | **H0 - Breaker Replacements (Qty 3):** Which breakers are being replaced? Shouldn't Reid be included on this project instead of H0? What do the three breakers being replaced supply power too? What is matter with the current breakers? Do the current breakers have any value? | These three breakers provide power to shared areas. MCC 1B breaker provides power to MCC 1B that provides power to the main Office AC unit. Start Up Power Panel breaker provides power to a main panel that provides power to the shops. Unit 1 Power Panel provides power to the offices and warehouse. These breakers are original 50 year old Westinghouse DB-25 breakers. New retrofit breakers have digital relay tripping, new mechanisms and less maintenance requirements. DB-25 breakers are obsolete. These breakers are going to continue to be used for station power in forseeable future. No scrap value. |
| 49-50 | 23 | 2 | **H1 - Mist Eliminator Panels:** How long have the current panels been in service? The description on page 28 states: "This project will be bid in the fall of 2014 and arrive in 2015." | (1) Since 2009 (2) "This project will be bid in the fall of 2015 and arrive in 2016" |
| 51 | 23 | 3 | **H1 - MCC "C" Additional Sections:** HMP&L requests that this project be removed from the Operating Plan. | Why does HMP&L request this item be removed? BREC disagrees. Currently there are no spare buckets available on any of the main MCCs in the plant. Also, this addition will provide the ability to feed this MCC from the Scrubber to reduce loading on the main 480V load centers that are currently operating at maximum loading. |
| 52 | 23 | 4 | **H0 - MATS -FGD Modifications:** How did the test go with 2 pump operation? | HCl Testing in March 2015 revealed marginal compliance on both units. Re-testing will be conducted after control efficiency improvements are performed. |
| 53-58 | 23 | 5 | **H1 - Catalyst Air Sweepers:** Last year to solve the problem of ash buildup BREC recommended the purchase of 12 sonic horns for H-2, budgeted at $70,000.00. Since there was no indication that the new horns would be more effective than the old horns, HMP&L suggested purchasing only 4 horns to test their effectiveness. The new horns did not solve the problem. HMP&L, now has the same questions about the sweepers. How many sweepers are being purchased? Where will the sweepers be installed? Can this amount be reduced to see if the sweepers will be effective? Are there other options to deal with the problem of ash buildup? What does the OEM and/or Catalyst supplier recommend? What are the plans for the sonic horns that have been installed? | the top layer of H1 catalyst modules. Amount cannot be reduced due to it being one system. After removing the H1 for a five day outage we found large piles of ash covering a total of 28 modules and with the new MATS regulation coming into effect next April and to be able reduce the mercury through are catalyst management program we need to keep the pluggage as low as possible. After discussing this issue with SCR-Tech they showed me the Air Sweeper technology. I have talked to three other Utility companies who have installed Air Sweepers due to ash pluggage all three have said the sweepers have reduced Ash pluggage 90%. I have looked at other options and the Air Sweepers seem to be the product with the best results and cost. The catalyst OEM supplier recommends ash sweepers. We will keep the sonic horns that have been installed and use as an extra ash removal system. |
| 59-62 | 23 | 6 | **H1 - DCS Process Controllers:** How many DCS Process Controllers will be replaced? Why do the current controllers need to be replaced? Is there any value to the communication cards being replaced? Are the current cards being kept in the warehouse? | Targeted to replace 12 NIS/NPM pairs. Age of the old controllers along with improved reliability and performance of the new communication modules. We have talked to ABB about buying the modules before and there is not any value to selling them back. We currently keep one pair in the warehouse stock. |

## Henderson Station Two Operating Plan 2015/2016

### Comments and Questions

| Q# | Pg | #/Pg | Questions or Comments | Comment/Answer |
|---|---|---|---|---|
| 63-67 | 23 | 7 | **H1 - Hot End Air Heater Baskets & H1 - Cold End Air Heater Baskets:** How long have the hot & cold baskets been in service? What was the total cost (including labor) for each, the last time they were replaced? The description on page 24 for the hot end baskets states "The baskets will be ordered in 2014 with deliver in 2015." Do we have to replace both sets during the 2015/2016 budget year? If so HMP&L requests reports and backup information. | CE have been in service since 2012, HE since 2004. $500k/ea. "This project will be bid in the fall of 2015 and arrive in 2016". YES, HE is deteriorated and fallen out and the CE 'A' side was severly damaged to excesive erosion caused by a hole in the steam cleaning device spray nozzle. The typical Life Span on CE baskets in a horizontal Air Heater on a Coal Fired Unit is 4-5 years. Reports sent to Ken. |
| 68-69 | 23 | 8 | **RH - Barge Unloader Buckett:** Is The $125,000.00 for rebuilding the buckett now in service? If so will it be rebuilt during the 2015/2016 fiscal year? | No. This money is to replace the existing unloader bucket. This is planned to be completed in 2015/16 FY. |
| 70-73 | 23 | 9 | **H0 - MATS Monitors:** Where will the new monitors go? Will any replace current monitors? How many HCL monitors will be purchased? How many particulate monitors will be purchased? | HCl Monitors will be installed on the monitoring platform of the stack. No current monitors will be replaced. Two (2) HCl monitors will be purchased. No new particulate monitor will be purchased in the period covered by the 2015-2016 operating plan. |
| 74-78 | 23 | 10 | **H0 - Cooling Tower Fan Shrouds (Qty 5):** Where will the new shrouds go? What is the problem with the current shrouds? HMP&L request the reports and backup information for this project. Can the purchase of shrouds be spaced out over several years? The description on page 26 for this project looks to be for fans and not shrouds. | H1-A, H2-B, H2-A, H1-E, H1- F. They are failing and in some cases have been hitting the fans. Reports were sent to Ken Brooks on Mon 5/12/2014 at 10:16 AM. No, it is recommended to replace these now. Others will follow in the future. |
| 79-82 | 23 | 11 | **H2 - SCR Catalyst Regen (Bottom Layer):** Shouldn't this project be for H1 instead of H2? The description on page 25 looks to be for 2015 instead of 2016. What was the total cost (including labor) for this project the last time catalyst was replaced? HMP&L requests a copy of the Catalyst Management Plan for H-1. | This is a regeneration of H2 Catalyst, but this layer will be installed in H1. Description will be updated. The total cost was $390,000. A copy of H1 Catalyst sample analysis was sent to Ken. |
| 83-87 | 23 | 12 | **H1 - DCS Power Supply Upgrade:** Why do the DCS power supplies need upgrading? How long have the current power supplies been in service? How many power supplies will be upgraded? Do the replaced power supplies have any value? Are the current power supplies or parts kept in inventory? | The existing Power Supplies have been in service from 7-10 years and the recommended replacement schedule is 5 years. We are planning to replace 10 power supplies. We have talked to ABB about buying the power supplies back before and there is not any value to selling them back. We currently do not stock replacement power supplies. |
| 88-90 | 23 | 13 | **H1 - Trunnion Bearing ("B"):** Is this for a new or refurbished bearing? Have any of the bearings removed from the other trunnion projects been refurbished? The description on page 28 states Procurement will take place in 2014 with delivery in 2015. | The bearings we take out of H2A Mill this year will be sent out and repoured and installed in H1B Mill in 2016. We installed new bearings in H2B Mill in 2013 sent them out to be repoured then installed them in H1A Mill in 2015. The description on page 28 is wrong should be 2015 with delivery in 2016. |
| 91 | 23 | 14 | **H0 - HCL Process Monitors & H-0 - MATS Monitors:** What is the difference? Both descriptions state "Additional HCL and PM monitors." | The lines labeled "H0 - HCl Process Monitors (Qty 2)" and "H0 - MATS Monitors" need to be combined and increased $50k for a total of $300k. This will be to purchase HCl monitors for Station Two for quarterly stack testing. |
| 92-93 | 23 | 15 | **H0 - HCL Process Monitors (Qty 2):** Where will these monitors go? Will both monitors be HCL? | See Question #90 above. |
| 94-95 | 23 | 16 | **H1 - HMI Back-up Computer:** Is there a current system that backs up the critical control system and if so why does it need to be replaced? If applicable, how long has the current system been in service? | There is currently no back-up system in place. |
| 96-97 | 23 | 17 | **H1 - ABB DCS Controls & HMI Upgrade:** Is there any value to the controls being replaced? Are parts kept in inventory? | No. No parts are kept in inventory. |
| 98-99 | 23 | 18 | **H0 - CEM DAHS & Remotes:** Does the current hardware have any value? Are spare parts kept in inventory? | This project will be deferred to the next Fiscal Year due to software availability. |
| 100 | 23 | 19 | **H1 - Cooling Tower Top Deck:** Is $300,000.00 too much for this project? H-2 is being replace, this cost is $363,483.00 which includes material and labor to replace fill in one of the cells. | No it's not too much, there are numerous floor joists/fan joists that are deteriorated and will need replacement upon inspection and removal of the existing floor decking. Structural repairs on the cooling tower are performed on a T&M basis per the RFQ. |

## Henderson Station Two Operating Plan 2015/2016
### Comments and Questions

| Q# | Pg | #/Pg | Questions or Comments | Comment/Answer |
|---|---|---|---|---|
| 101-104 | 23 | 20 | **H1 - NEMS Umbilical Upgrade:** How many umbilicals are there on H-1 and H-2? How many have been replaced? How many umbilicals will be replaced under this project? Which ones will be replaced? Do these umbilicals accommodate other probes beside M&C brand? | There are currently 2 umbilicals on each unit going to the NEMS shelter. No umbilicals have been replaced since the SCR was built. Three will be installed to accommodate the installation of a second inlet probe. A total of 3 umbillicals will be installed for additional inlet probe, the existing inlet probe and the outlet probe. These new umbilicals will accommodate other manufacturers probes. |
| 105-107 | 23 | 21 | **H0 - NEMS Inlet Probe:** How will a second probe improve accuracy and efficiency? Are there other components in the system that lets the operator know that the existing probe is not working correctly? How has BREC handle the inaccuracy and inefficiencies in the past? | The addition of a second probe will give us a better cross-sectional sample reading to improve overall measurement accuracy and assist in boiler tuning due to the EPAs best standard operating practices. The operator can look at the display and determine if the reading is excessively high or low. BREC is constantly trying to make improvements to achieve greater efficiency to decrease operating cost, thus increase savings for BREC and HMPL. |
| | | | | |
| 108 | 33 | 1 | **SIIG - Ops Adninistrative:** Why has this item increased by 50% from last year? | Same Question as page 37 - Should the Summary Pages be removed from the budget for less confusion? |
| 109 | 33 | 2 | **RGSII - Non-Fuel Equipment:** Why has this item increased by 60% from last year? | Increased less than $282.00 Total |
| 110 | 33 | 3 | **RGSII - Ops Administrative:** Why has this item increased by 72% from last year? | This project is offset by RHOADM and STOADM |
| 111 | 33 | 4 | **RGSII - FH - Ops Consumables:** Why has this item increased by 99% from last year? | Total routine O&M increased by 3.6% primarily due to Environmental regulations & Inflation. All projects were aligned based on previous yr's project spend. |
| 112 | 33 | 5 | **RSII - FH - Ops Tool Room:** Why has this item increased by 33% from last year? | Total routine O&M increased by 3.6% primarily due to Environmental regulations & Inflation. All projects were aligned based on previous yr's project spend. |
| 113 | 33 | 6 | **RSII - Air System:** Why has this item increased by 32% from last year? | Total routine O&M increased by 3.6% primarily due to Environmental regulations & Inflation. All projects were aligned based on previous yr's project spend. |
| 114 | 33 | 7 | **RSII - Site Mtce/Improvements:** Why has this item increased by 76% from last year? | Total routine O&M increased by 3.6% primarily due to Environmental regulations & Inflation. All projects were aligned based on previous yr's project spend. |
| | | | | |
| 115 | 34 | 1 | **RSII - Ops consummables:** Why has this item increased by 112% from last year? | Total routine O&M increased by 3.6% primarily due to Environmental regulations & Inflation. All projects were aligned based on previous yr's project spend. |
| 116 | 34 | 2 | **RSII - Ops Buildings & Grounds:** Why has this item increased by 49% from last year? | Total routine O&M increased by 3.6% primarily due to Environmental regulations & Inflation. All projects were aligned based on previous yr's project spend. |
| 117 | 34 | 3 | **SII - CEM:** Why has this item increased by 57% from last year? | Total routine O&M increased by 3.6% primarily due to Environmental regulations & Inflation. All projects were aligned based on previous yr's project spend. |
| 118 | 34 | 4 | **SII - Scrubber System:** Why has this item increased by 42% from last year? | Total routine O&M increased by 3.6% primarily due to Environmental regulations & Inflation. All projects were aligned based on previous yr's project spend. |
| 119 | 34 | 5 | **SII - Fans/Draft System:** Why has this item increased by 34% from last year? | Total routine O&M increased by 3.6% primarily due to Environmental regulations & Inflation. All projects were aligned based on previous yr's project spend. |
| 120 | 34 | 6 | **SII - Waste Water Treatment:** Why has this item increased by 45% from last year? | Total routine O&M increased by 3.6% primarily due to Environmental regulations & Inflation. All projects were aligned based on previous yr's project spend. |
| | | | | |
| 121 | 35 | 1 | **SII - Ops Boilers and Burners:** Why has this item increased by 179% from last year? | Total routine O&M increased by 3.6% primarily due to Environmental regulations & Inflation. All projects were aligned based on previous yr's project spend. |
| 122 | 35 | 2 | **H2 - Planned Outage - Ops:** Why has this item increased by 92% from last year? | If you compare the lines in the project you will see there is a Chemical Clean in 2016. |
| 123 | 35 | 3 | Shouldn't the planned outage be for H1 instead of H2? | Yes, the project number was changed to H1, but not description. |

Henderson Station Two Operating Plan 2015/2016

Comments and Questions

| Q# | Pg | #/Pg | Questions or Comments | Comment/Answer |
|---|---|---|---|---|
| 124-126 | 37 | 1 | **HGOADM Protective Clothing (Uniforms):** This item was not in this section last year, is it new or was it moved from a different section? If so where? If it was included in Rountine item last year why the 50% increase? | Same question as #108 above. Scrubber Employee Uniforms, etc. |
| 127 | 37 | 2 | **Vehicle Mtce - #384, #442 & Forklift:** Why has this item increased by 200% from last year? | For consistency - All vehicles were allocated in the budget at the same amount for repairs. Other vehicle lines were reduced, which is not mentioned. |
| 128 | 37 | 3 | **921 Case Endloader:** Why has this item increased by 67% from last year? | Some funds from previous year's routine line where allocated to this line in the project. |
| 129 | 37 | 4 | **Auger Sampler:** Why has this item increased by 50% from last year? | Some funds from previous year's routine line where allocated to this line in the project. |
| 130 | 37 | 5 | **Bobcat Skidsteer:** Why has this item increased by 100% from last year? | Some funds from previous year's routine line where allocated to this line in the project. |
| 131 | 37 | 6 | **CH Vehicles - #254, 389, 391, 392, 445:** Why has this item increased by 100% from last year? | For consistency - All vehicles were allocated in the budget at the same amount for repairs. Other vehicle lines were reduced, which is not mentioned. |
| 132 | 37 | 7 | **Lab Vehicles - #269 & 386:** Why has this item increased by 100% from last year? | For consistency - All vehicles were allocated in the budget at the same amount for repairs. Other vehicle lines were reduced, which is not mentioned. |
| 133 | 37 | 8 | **Station Vehicles - #383, 394, 395, 404 & 431:** Why has this item increased by 100% from last year? | For consistency - All vehicles were allocated in the budget at the same amount for repairs. Other vehicle lines were reduced, which is not mentioned. |
| 134 | 37 | 9 | **Warehouse Fork Lift:** Why has this item increased by 100% from last year? | Some funds from previous year's routine line where allocated to this line in the project. |
| 135 | 37 | 10 | **SIIG - Ops Administrative Total:** Why has this item increased by 50% from last year? | Third time this question has been asked. Should the Summary Pages be removed from the budget for less confusion? |
| | | | | |
| 136 | 38 | 1 | **Office/Computer Supplies & Office Equip Mtce:** Why has this item increased by 117% from last year? | Same question as #110 above. Should the summary pages be removed from the budget for less confusion? |
| 137 | 38 | 2 | **Travel Expenses:** Why has this item increased by 41% from last year? | Same question as #110 above. Should the summary pages be removed from the budget for less confusion? |
| 138 | 38 | 3 | **RGSII - Ops Administrative:** Why has this item increased by 72% from last year? | Same question as #110 above. Should the summary pages be removed from the budget for less confusion? |
| 139 | 38 | 4 | **Coal Handling supplies, filters:** Why has this item increased by 100% from last year? | Same question as #111 above. Should the summary pages be removed from the budget for less confusion? |
| 140 | 38 | 5 | **RGSII - FH - Ops Tool Room:** Why has this item increased by 100% from last year? | Same question as #112 above. Should the summary pages be removed from the budget for less confusion? |
| 141 | 38 | 6 | **Miscellaneous, tools, wrenches, etc:** Why has this item increased by 33% from last year? | Same question as #113 AND #140. Duplicate questions appear to be an issue every year. |
| 142 | 38 | 7 | **RSII - FH - Ops Tool Room:** Why has this item increased by 33% from last year? | Same question as #112 AND #140. Duplicate questions appear to be an issue every year. |
| | | | | |
| 143-148 | 39 | 1 | **D8N Dozer - Repairs/Maintenance:** The D8T was purchased new last year to replace the D8N. The budget for the D8N over the last two years is $120,000.00. What repairs were done on the D8N in 2014/2015? What was the total spend in 2014/2015 for this item? What repairs are planned for in 2015/2016? Can the $60,000.00 be reduced? Is D8N worth keeping in service at $60,000.00/year? | The D8N was not purchased to replace the D8T. We replaced the torque converter, radiator, power train cooler, water pump thermostat. The total spend was approximately $25k. It is in need of a new air conditioner (Estimated cost is 5,000). This line can be reduced to $22k. |

## Henderson Station Two Operating Plan 2015/2016

### Comments and Questions

| Q# | Pg | #/Pg | Questions or Comments | Comment/Answer |
|---|---|---|---|---|
| 149-151 | 40 | 1 | **Replace Control Cards:** Are control cards actually being replaced? Last year BREC stated. "A project analysis was completed for the last two years on this project and we are not spending money on cards. However we have overspent this project the last two years. I request we leave this money in but change the name. Unloader Drives - 6K, Unloader Feeder - 3K, Unloader Hopper - 9K." If cards are to be replaced where will they be used and how many are to be purchased? | Yes, this description should have been changed and amount should remain the same. |
| 152 | 41 | 1 | **RSII - Air System:** Why has this item increased by 32% from last year? | Same question as #113 above. Should the summary pages be removed from the budget for less confusion? Duplicate questions require unnecessary research and time. |
| 153-155 | 41 | 2 | **Door & Frame Replacement:** Why has this item increased by 107% from last year? Does BREC have specific doors in mind to be replaced? How many doors will be replaced? HMP&L request that this amount be reduced. | On average we replace 2 to 3 doors. Specific doors have not yet been identified. BREC will reduce to $16,000. |
| 156 | 41 | 3 | **RSII - Site Mtce/Improvements:** Why has this item increased by 76% from last year? | EXACT same question as #114 and #153 above. Duplicate questions require unnecessary research and time. Should SUBTOTALS be removed from the budget for less confusion? |
| 157 | 41 | 4 | **Mtc Vehicle Mtce - #399, 400, 402, 403 & 435:** Why has this item increased by 100% from last year? | Total routine O&M increased by 3.6% primarily due to Environmental regulations & Inflation. All projects were aligned based on previous yr's project spend - aging vehicles and equipment |
| 158 | 41 | 5 | **Forklift/JLG 10,000 lb:** Why has this item increased by 50% from last year? | Total routine O&M increased by 3.6% primarily due to Environmental regulations & Inflation. All projects were aligned based on previous yr's project spend - aging vehicles and equipment |
| 159 | 41 | 6 | **S65 - Manlift/Genie:** Why has this item increased by 100% from last year? | Total routine O&M increased by 3.6% primarily due to Environmental regulations & Inflation. All projects were aligned based on previous yr's project spend - aging vehicles and equipment |
| 160 | 41 | 7 | **RSII - Mtc Plant Vehicles:** Why has this item increased by 27% from last year? | Total routine O&M increased by 3.6% primarily due to Environmental regulations & Inflation. All projects were aligned based on previous yr's project spend - aging vehicles and equipment |
| 161 | 41 | 8 | **Polaris:** The polaris has been in the FGD shop for several months with a flat tire. Is the Polaris still going to be used at Reid/SII? | Yes, the polaris is still used at Reid/SII. It is not suitable for winter months. We keep it in storage at the FGD shop. |
| 162-163 | 42 | 1 | **Barge Cleaning - Walkways:** Why has this item increased by 71% from last year? Who cleans the walkways? | This amount can be reduced to the 2014/2015 budget figure - $4,000. Green River Barge Services. |
| 164-165 | 42 | 2 | **Dredge River:** Why has this item increased by 67% from last year? How much has been spent on dredging the river in the current budget? | There was no dredging performed in 2014/2015 due to waiting on approval from Corp of Eng. permit. This work is planned to be done in 2015/2016 FY. Increased $ amount due to riverbank washout @ HMPL cells. |
| 166 | 42 | 3 | **Production Supplies, filters, etc.:** Why has this item increased by 112% from last year? | Total routine O&M increased by 3.6% primarily due to Environmental regulations & Inflation. All projects were aligned based on previous yr's project spend. |
| 167 | 42 | 4 | **RSII - Ops Consumables:** Why has this item increased by 112% from last year? | EXACT same question as #166 above. Duplicate questions require unnecessary research and time. Should SUBTOTALS be removed from the budget for less confusion? |
| 168 | 43 | 1 | **Chemicals/Heating Fuels - Winterization:** Why has this item increased by 67% from last year? | Lines were combined. Amount actually decreased. Same question as #116 above. |
| 169 | 43 | 2 | **Outside Janitorial Services:** Why has this item increased by 69% from last year? | Total routine O&M increased by 3.6% primarily due to Environmental regulations & Inflation. All projects were aligned based on previous yr's project spend. Same question as #116 above. |
| 170 | 43 | 3 | **RSII - Ops Building & Grounds:** Why has this item increased by 74% from last year? | EXACT same question as #168 and #169 above. Duplicate questions require unnecessary research and time. Should SUBTOTALS be removed from the budget for less confusion? |

## Henderson Station Two Operating Plan 2015/2016

### Comments and Questions

| Q# | Pg | #/Pg | Questions or Comments | Comment/Answer |
|---|---|---|---|---|
| 171 | 43 | 4 | **Wet Bottom Nozzle System:** Why has this item increased by 200% from last year? | This increased by $1,750. Previous line labeled "Wet Bottom Pit Hydroejector" was added to this line. |
| | | | | |
| 172 | 44 | 1 | **Cooling Tower:** Why has this item increased by 150% from last year? | A portion of the "Routine" line in this project was added to this line. |
| 173 | 44 | 2 | **Cooling Tower Screens:** Why has this item increased by 253% from last year? | A portion of the "Routine" line in this project was added to this line. |
| 174-175 | 44 | 3 | **STMCWS Cooling Tower Top Deck Repairs:** Does BREC need $12,000.00 for this project since the deck is being replaced on H-2 and there is money in budget to replace H-1 in this fiscal year. | Reduce it down to $5,000 |
| 176 | 44 | 4 | **Rebuild 480V Load Center Breakers:** How many breakers is BREC planning on rebuilding? | The plan is to re-build 6 to 8 of the substation breakers throughout the year as pit stops and time allows. |
| | | | | |
| 177-180 | 45 | 1 | **Mercury Trap PMs:** Will this be part of the new mercury monitors? If so when will the mercury monitors be placed in service? Will this item be used this fiscal year? If so, can the $12,000.00 be reduce? | Yes. New mercury trap systems will be installed at H-1 and H-2 in May 2015 and certified in June 2015. These trap systems will be used to demonstrate compliance when the MATS rule becomes effective in April 2016. The trap systems will be operated from June 2015 to April 2016 to ensure compliance before the April 2016 compliance deadline. |
| 181-184 | 45 | 2 | **Mercury Filter Traps:** Will this be part of the new mercury monitors? If so when will the mercury monitors be placed in service? Will this item be used this fiscal year? If so, can the $21,000.00 be reduce? | Duplicate question. See answers above. |
| 185 | 45 | 3 | **Valves & Parts:** Why has this item increased by 53% from last year? | Increased $2,250. Total routine O&M increased by 3.6% primarily due to Environmental regulations & Inflation. All projects were aligned based on previous yr's project spend. |
| 186 | 45 | 4 | **SII - CEM:** Why has this item increased by 57% from last year? | Duplicate question. See answers above. |
| 187 | 45 | 5 | **Pumps:** Why has this item increased by 167% from last year? | Increased routine maintenance and overhauls on the pumps due to imposed environmental regulations that require more usage of the pumps. |
| 188 | 45 | 6 | **SII - Scrubber System:** Why has this item increased by 42% from last year? | Duplicate question. See answer to Q# 187 above. |
| | | | | |
| 189-190 | 46 | 1 | **Boiler Structure Door & Frame Replacement:** How many doors is BREC planning on replacing? Why has this item increased by 37% from last year? | Increased $3,800. On average we replace 2 to 3 doors. The average cost for a single door is $4,500 |
| | | | | |
| 191 | 47 | 1 | **SII - Fans/Draft System:** Why has this item increased by 34% from last year? | Duct work repairs are getting more extensive, due to deterioration and more maintenance repairs. |
| 192 | 47 | 2 | **PA and Seal Air Fans:** Why has this item increased by 120% from last year? | Combined this line and the routine line. Project only increased $5k. |
| 193 | 47 | 3 | **Drains and Piping:** Why has this item increased by 50% from last year? | The drains and piping repairs are getting more extensive, due to deterioration and more maintenance repairs. |
| 194 | 47 | 4 | **Annual Catalyst Sample & Analysis:** Why has this item increased by 100% from last year? | Increase in Analysis cost - not charged in previous budgeted years. |
| 195 | 47 | 5 | **Catalyst Management Program:** Why has this item increased by 32% from last year? | Quotes from Catalyst Mgmt increased. |
| | | | | |
| 196 | 48 | 1 | **SII - Ops Boilers and Burners:** Why has this item increased by 179% from last year? | This projects was underfunded in previous years. The budget has been aligned to accommodate the extra spending primarily for waterblasting and vacuuming. |

## Henderson Station Two Operating Plan 2015/2016
### Comments and Questions

| Q# | Pg | #/Pg | Questions or Comments | Comment/Answer |
|---|---|---|---|---|
| 197 | 48 | 2 | **Bottled Gas:** Why has this item increased by 50% from last year? | Oversight - Should have $3,000 per for E.H. fluid and $2,000 per month in Bottled gases |
| | | | | |
| 198 | 52 | 1 | **ST1PLO-OPS Boiler Chemical Clean:** HMP&L requests copies of data and reports supporting that a boiler cleaning needs to be done at this time for our files. | Reports were sent to Ken. A chemical clean is recommend. H-1 was last chemically cleaned in November of 2005. Boilers are typically cleaned around a 10 year time frame. |
| | | | | |
| 199 | 53 | 1 | **Vacuum Penthouse:** Why has this item increased by 54% from last year? | The cost of vacuuming the penthouse has continued to increase each year due to fact of trying to control gas leaks. |
| 200 | 53 | 2 | **FGD - Clean & Inspect Hastalloy Area Reaction Tank:** Why has this item increased by 140% from last year? | Materials and fabrication to replace sections of the absorber module will increase this cost from last year. |
| 201 | 53 | 3 | **Nox - AIG Valve/Piping Inspection/Repairs/Replacement:** Why has this item increased by 1,400% from last year? | The scope has increased based on previous inspections. |
| | | | | |
| 202 | 54 | 1 | **TURB - Test & Recondition Breakers:** Why has this item increased by 93% from last year? | This budget can be reduced to $15k. |
| | | | | |

HMP&L HENDERSON MUNICIPAL POWER & LIGHT

December 27, 2017

Lindsay N. Durbin, CPA
Chief Financial Officer
Big Rivers Electric Corp.
201 Third St.
P.O. Box 24
Henderson, Ky. 42419-0024

**RE: Henderson Station Two Operating Plan 2017-2018**

Dear Lindsay:

As you know, disagreements between HMP&L and Big Rivers concerning responsibility for certain expenses related to Station Two have to date precluded approval of a Henderson Station Two operating plan for 2017-2018.

Specifically, HMP&L contests responsibility for MISO load expenses and transmission charges, as there is still no formal agreement in place concerning those items. HMP&L also objects to the inclusion of certain landfill-related expenses in its annual capacity payment. HMP&L maintains that HMP&L is contractually obligated to pay only for the transportation and placement of pozatec and ash at the landfill, and not for landfill maintenance or improvements that would include but not be limited to the construction of high walls designed to extend the life of the landfill. HMP&L also objects to the calculation of HMP&L's share of disposal costs (the "City factor") to the extent the calculation includes waste associated with the generation of uneconomic energy unwanted by either HMP&L or Big Rivers.

Despite the ongoing dispute concerning these budget items, HMP&L, in the spirit of cooperation, and in the interest of approving a 2017-2018 operating plan, is agreeable, for the 2017-2018 fiscal year only, to a capacity payment that includes MISO load expenses and MISO transmission charges associated with Station Two, and calculated according to the Station Two capacity split. HMP&L further agrees, for the 2017-2018 fiscal year only, to approve a capacity payment that includes disposal costs of $5.85 per ton, even though that figure includes payment for disputed expenses. HMP&L tentatively agrees to approve a final draft of the operating plan, subject to the caveats set forth in this letter.

**Please be aware that HMP&L continues to dispute responsibility for the budget items described in this letter under the provisions of the Station Two contracts. HMP&L therefore reserves and does not waive its right to demand recovery of disputed expenses from Big Rivers.**

We hope that this will address the outstanding issues associated with the proposed budget in a way that will allow the parties to approve a current operating plan. We appreciate your cooperation, and invite you to contact us with any questions or concerns.

Sincerely,

K. M. Brooks

K. M. Brooks
Power Supply Director
Henderson Municipal Power & Light
100 Fifth Street
P.O. Box 8
Henderson, KY
42419-008