COMMONWEALTH OF KENTUCKY

BEFORE THE

PUBLIC SERVICE COMMISSION OF KENTUCKY

IN THE MATTER OF

AN EXAMINATION OF THE APPLICATION	)	
OF THE FUEL ADJUSTMENT CLAUSE OF	)	
KENTUCKY POWER COMPANY FROM	)	CASE NO. 2014-00225
NOVEMBER 1, 2013 THROUGH APRIL 30, 2014	)	

KENTUCKY POWER COMPANY RESPONSE TO COMMISSION STAFF'S SECOND SET OF DATA REQUESTS

September 15, 2014

VERIFICATION

The undersigned, John A. Rogness III, being duly sworn, deposes and says he is the Director Regulatory Services for Kentucky Power, that he has personal knowledge of the matters set forth in the forgoing responses for which he is the identified witness and that the information contained therein is true and correct to the best of his/her information, knowledge and belief.

John A. Rogness III

COMMONWEALTH OF KENTUCKY)
) Case No. 2014-00225
COUNTY OF FRANKLIN)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by John A. Rogness III, this the 12th day of September 2014.

Judy K Rosquist 48393
Notary Public

My Commission Expires: January 23, 2017

VERIFICATION

The undersigned, Kelly D. Pearce, being duly sworn, deposes and says he is the Director Contract and Analysis for American Electric Power, that he has personal knowledge of the matters set forth in the forgoing responses for which he is the identified witness and that the information contained therein is true and correct to the best of his information, knowledge and belief

Kelly D. Pearce

Kelly D. Pearce

STATE OF OHIO	)	
	)	Case No. 2014-00225
COUNTY OF FRANKLIN	)	

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Kelly D. Pearce, this the 11th day of September 2014.

Charmaine S. Hamilton

Notary Public

My Commission Expires: ____________________

NOTARIAL SEAL STATE OF OHIO

CHARMAINE S. HAMILTON
Notary Public, State of Ohio
My Commission Expires 05-14-2017

Kentucky Power Company

REQUEST

Refer to Kentucky Power's response to Item 26 of the Commission's August 13, 2014 Request or Information ("August 13, 2014 Request").

a. Kentucky Power makes reference to 807 KAR 5:056 Section 1(3), KRS 278.160, and the Commission's Order dated February 7, 2005, in Case No. 2004-00430.[1] Provide the specific text of the regulation and statute and the specific page number and text of the Order to which Kentucky Power is referring in this response.

b. Refer to the February 7, 2005 Order issued in Case No. 2004-00430 referenced in Kentucky Power's response. The top of page 4 states that the 807 KAR 5:056, Section 1(3) "also permits the recovery of 'actual identifiable fossil and nuclear fuel costs associated with energy purchased' in non-economy transactions." This statement is footnoted and refers the reader to the May 2, 2002 Orders issued in both Case No. 2000-00495-B[2] and Case No. 2000-00496-B[3] "for a discussion of the methodology for calculating the fuel cost of such transactions." On page 5 of the May 2, 2002 Order in Case No. 2000-00495-B, the Commission states:

We interpret Administrative Regulation 807 KAR 5:056 as permitting an electric utility to recover through its FAC only the lower of the actual energy cost of the non-economy purchased energy or the fuel cost of its highest cost generating unit available to be dispatched to serve native load during the reporting expense month. Costs for non-economy energy purchases that are not recoverable through an electric utility's FAC are considered

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[1] Case No. 2004-00430, East Kentucky Power Cooperative's Request for a Declaratory Ruling on the Application of Administrative Regulation 807 KAR 5:056 to its Proposed Treatment of Non-Economy Energy Purchases (Ky. PSC Feb. 7, 2005).

[2] Case No. 2000-00495-B, An Examination by the Public Service Commission of the Fuel Adjustment Clause of American Electric Power Company from May 1, 2001 to October 31, 2001 (Ky. PSC May 2, 2002).

[3] Case No. 2000-00496-B, An Examination by the Public Service Commission of the Fuel Adjustment Clause of East Kentucky Power Cooperative, Inc. from May 1, 2001 to October 31, 2001 (Ky. PSC May 2, 2002).

"non-FAC expenses" and, if reasonably incurred, are otherwise eligible for recovery through base rates.

The Order, also on page 5, goes on to state that "[w]e place AEP on notice that this interpretation shall be applied to all energy purchases made after April 30, 2002." Because Kentucky Power (d/b/a American Electric Power at that time) was unique in that it did not own a combustion turbine, it sought and was granted rehearing in that proceeding. By Order dated October 3, 2002, Kentucky Power was granted authority to use the "Peaking Unit Equivalent" approach to calculate the level on non-economy purchase power costs to recover through the fuel adjustment clause ("FAC"). The Peaking Unit Equivalent was based on the operating characteristics of a General Electric simple-cycle gas turbine.

(1) Given the language in the May 2, 2002 and October 3, 2002 Orders issued in Case No. 2000-00495-B, explain why Kentucky Power believes it is appropriate to include the entire cost of non-economy purchases in the calculation of the FAC.

(2) For each month of the period under review, provide the dollar amount of power purchases that were made because of a planned outage that were included in the calculation of the FAC and the dollar amount of power purchases that would have been included had Kentucky Power applied the "Peaking Unit Equivalent" approach approved in the October 3, 2002 Order in Case No. 2000-00495-B.

RESPONSE

a. In its August 27, 2014 response to the Staff's August 13, 2014 Request, Kentucky Power referenced the following portions of the statute, regulations and Order:

<u>KRS 278.160(2)</u>:

No utility shall demand, collect, or receive from any person a greater or less compensation for any service rendered or to be rendered than that prescribed in its filed schedules, and no person shall receive any service from any utility for a compensation that is greater or less than that prescribed in such schedules.

<u>807 KAR 5:056(3)</u>:

Fuel costs (F) shall be the most recent actual monthly cost of:

(b) The actual identifiable fossil and nuclear fuel costs associated with energy purchased for reasons other than identified in subsection (c) of this subsection, but excluding the cost of fuel related to purchases to substitute for forced outages.

(c) The net energy cost of energy purchases, exclusive of capacity and demand charges (irrespective of the designation assigned to such transaction) when such energy is purchased on an economic dispatch basis. Included therein may be such costs as the charges for economy energy purchases and the charges as a result of scheduled outage, all such kinds of energy being purchased by the buyer to substitute for its own higher cost energy;

<u>February 7, 2005 Order in Case No. 2004-0043[4]</u>

Page 1:

At issue is whether the proposed method, East Kentucky Power Cooperative's proposed method was to report [5] which requires EKPC to underreport its cost of fuel, conflicts with Administrative Regulation 807 KAR 5:056. Finding that Administrative Regulation requires an electric utility to report its actual cost of fuel, we find that the proposal conflicts with that regulation.

Page 4:

It [807 KAR 5:056, Section 1(3)] also permits the recovery of "actual identifiable fossil and nuclear fuel costs associated with energy purchased" in non-economy transactions.[3]

The EKPC proposal conflicts with the literal language of Administrative Regulation 807 KAR 5:056, which states:

Fuel costs (F) **shall be** the most recent **actual** monthly cost of:

. . .

(b) **The actual identifiable fossil and nuclear fuel costs associated with energy purchased for reasons other than identified in paragraph (c) of this subsection, but excluding the cost of fuel related to purchases to substitute for forced outages**; plus

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[4] *In the Matter of: East Kentucky Power Cooperative's Request For A Declaratory Ruling On The Application Of Administrative Regulation To Its Proposed Treatment Of Non-Energy Purchases.*

[5] East Kentucky Power Cooperative's proposed method was to report "the cost of any non-economy energy purchases made at times when all available EKPC generating capacity is serving native load as $0.00." Order, *In the Matter of: East Kentucky Power Cooperative's Request For A Declaratory Ruling On The Application Of Administrative Regulation To Its Proposed Treatment Of Non-Energy Purchases*, Case No. 2004-00430 at 2 (Ky. P.S.C. February 7, 2005).

... (emphasis in original).

Page 5

The regulation prescribes a strict procedure for accounting and reporting fuel costs and requires the reporting of all fuel costs. It does not allow any discretion to a utility to ignore or underreport such costs that are otherwise considered a "fuel cost" or to use other than actual costs.

KRS 278.160(2), furthermore, requires EKPC to charge an FAC charge that reflects the total cost of non-economy energy purchases. It provides:

No utility shall demand, collect, or receive from any person a greater or **less compensation** for any service rendered or to be rendered than that prescribed in its filed schedules, and no person shall receive any service from any utility for a compensation that is greater or less than that prescribed in such schedules.

EKPC's filed rate schedules set forth a formula for calculating its FAC charge that contains the same mandatory language that is contained in Administrative Regulation 807 KAR 5:056. As EKPC's proposal requires EKPC to ignore the formula and to assess an FAC charge other than that set forth in its filed rate schedules, it is contrary to KRS 278.160(2). (emphasis in original)

b. (1) The Company acknowledges footnote 3 of the Commission's Order. Nevertheless, the Commission's repeated reference at pages 4 and 5 of its subsequent February 7, 2005 Order in Case No. 2004-00430 to East Kentucky Power Cooperative's actual costs, combined with the Commission's denial of East Kentucky Power's request to use a cost other than its actual cost, clearly indicates the Commission interpreted its regulation to require that actual fuel costs of non-economic purchases, and not a proxy, be used in accounting and reporting fuel costs.

Subsequent to its February 7, 2005 Order in Case No. 2004-00430, Salt River Electric Cooperative Corporation sought intervention in the proceeding and rehearing of the Commission's February 7, 2005 Order. In denying rehearing, the Commission rejected Salt River's contention East Kentucky Power's purchases did not meet the definition of non-economy purchases in Case No. 2000-00496-B[6] which was identical to the definition in Case No. 2000-00495-B.) Order,. In doing so, the Commission explained:

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[6] 3 *In the Matter of: East Kentucky Power Cooperative's Request For A Declaratory Ruling On The Application Of Administrative Regulation To Its Proposed Treatment Of Non-Energy Purchases*, Case No. 2004-00430 at 5-6 (Ky. P.S.C. March 21, 2005)

The definition of "non-economy energy purchases" set forth in our Order in Case No. 2000-00496-B too narrowly construes 807 KAR 5:056 and conflicts with the regulation. A more accurate definition of non-economy energy purchases recognizes that the energy costs thereof may be greater or less than the variable cost of the highest cost generating unit available to serve native load. To the extent the definition in our Order in Case No. 2000-00496-B conflicts with our Order of February 7, 2005, we find that it was incorrect and should be overruled. *Id.* at 6.

The Commission's recognition in its March 21, 2005 Order in Case No. 2000-00430 that the cost of non-economy energy purchases "may be greater or less than the variable cost of the highest cost generating unit available to serve native load," coupled with its emphasis on the accounting and reporting of actual costs in its February 7, 2005 Order in the same proceeding, indicates that the entire, actual costs of the non-economy energy purchase should be used in lieu of any lesser or greater amount.

b. (2) To be filed September 16, 2014.

WITNESS: John A Rogness

Kentucky Power Company

REQUEST

Refer to Kentucky Power's response to Item 27 of the August 13, 2014 Request which states that "Kentucky Power includes 100% of the purchased power costs that it may incur during a time of an energy shortage that is not directly linked to a forced outage in the FAC."

a. Refer to the Commission's language quoted in Item 1.b. above and the May 2, 2002 Order issued in Case No. 2000-00496-B involving East Kentucky Power Cooperative, Inc. On page 5 of that Order, the Commission states:

In reaching our interpretation, we are mindful of EKPC's concerns regarding power purchases made under emergency circumstances. We recognize that in such circumstances wholesale power market prices may significantly exceed the fuel cost of EKPC's highest cost generating unit available to serve native load. In those circumstances, EKPC may apply to the Commission for immediate rate recovery of those costs.

(1) Given the language from the two Commission orders, explain why Kentucky Power believes it is appropriate to include the entire cost of non-economy purchases in the calculation of the FAC.

(2) For each month of the period under review, provide the dollar amount of power purchases that were made to meet demand (when Kentucky Power was not experiencing an outage) that were included in the calculation of the FAC and the dollar amount of power purchases that would have been included had Kentucky Power applied the "Peaking Unit Equivalent" approach approved in the October 3, 2002 Order in Case No. 2000-00495-B.

RESPONSE

a. 1) In addition to the reasons set forth in its response to KPSC 2-1(b)(1), Kentucky Power relies on the Commission's February 7, 2005 and March 21, 2005 Orders in Case No. 2004-00430. In the February 7, 2005 Order, the Commission denied East Kentucky Power Cooperative's request to absorb costs associated with purchases made to meet native load in excess of native generation requiring instead that East Kentucky Power to charge a FAC charge that reflects the total costs of the non-economy purchases. The Commission upheld this conclusion in the March 21, 2005 Order denying Salt River Electric Cooperative Corporation's motion for rehearing. Because the non-economy purchases for energy shortages described in the Company's response to Staff 1-27 are the same type of non-economy purchases that the Commission required East Kentucky Power to recover the total costs of via the FAC in Case No. 2004-00430, the Company similarly seeks to recover the total costs associated with these non-economy purchases via the FAC. The Commission's Order dated in Case No. 2004-00430 overturned the Commission's previous Order in Case No. 2000-00496B:

2) To be filed September 16, 2014.

WITNESS: John A Rogness

Kentucky Power Company

REQUEST

Refer to the response to Item 28 of the August 13, 2014 Request in which Kentucky Power states that "[r]unning all four units increased the amount of `no-load costs' that have been historically and properly allocated to internal customers." State whether the basis for the determination that the "no-load costs" were "properly allocated" is based on the fact that they have been allocated "historically" to internal customers. If not, provide the basis for the determination that the "no-load costs" were "properly allocated."

RESPONSE

The fact that no load costs are properly allocated to internal customers is not based solely on the fact that it has been done historically.

Regarding the reasons that such costs are properly allocated to internal load customers, both past and present, please refer the the Company's response to Staff 1-29 part b.

The Company's resources were constructed or obtained by contract for the purpose of serving internal load. The internal load has the first right to any and all of the Company's resources that are on-line in a given hour. In light of this right of "first-call," it is both reasonable and appropriate that the costs associated with making the units available be allocated to internal load customers. Further, units cannot be turned on and off by the hour depending solely on the then short term demand of internal load. The Rockport units, for example, have a cold start-up time of approximately 16 hours. Therefore, units that are on-line in a given hour are assumed first to satisfy internal load, and only the controllable dispatch between the unit minimums and maximums is available to make off-system sales (OSS).

After the fact, the controllable dispatch above the unit minimums is what is then "stacked" on a $/MWh basis. A "top-down" approach is used to allocate cost to OSS. For each hour, for each unit, the unit with the most expensive $/MWh cost of the last MWh produced is what is assigned to OSS. This MWh assignment will continue in this top-down approach whereby always the next most expensive $/MWh cost, selected from among all of the on-line units, is assigned to OSS until all OSS have been accounted for. The remaining cost, which has been reduced by this highest supply curve cost, remains with internal load.

WITNESS: Kelly D Pearce

Kentucky Power Company

REQUEST

Refer to the response to Item 29 of the August 13, 2014 Request.

a. Refer to the response to Item 29.a. State whether costs other than fuel costs are included in "no load costs." If so, identify the type of non-fuel costs included and state whether these costs are recovered through the FAC.

b. b. Refer to the response to Item 29.b.

1) The first paragraph states that "[n]o load costs' are not associated with specific increments of generation" and that "[b]ecause 'no load costs' do not change when generation is increased or decreased, economic dispatch does not provide a basis for allocation of `no load costs." State whether Kentucky Power's generating units are producing power during the time that "no load costs" are incurred. If so, explain the above statements and explain how the power that is generated is allocated (to internal load or off-system sales).

2) The second paragraph states that "[u]nits that are on-line in a given hour are assumed first to satisfy internal load, and only the controllable dispatch between the unit minimums and maximums may be available to make off-system sales (OSS) if additional economic power is available and it is not needed for internal load."

i. Provide the unit minimums and maximums for each of Kentucky Power's generating units, including Rockport.

ii. Provide the economic dispatch order for Kentucky Power's generating units, including Rockport.

iii. State whether the Rockport power purchased by Kentucky Power, Kentucky Power's share of the Mitchell units, and the Big Sandy units (all of these sources combined) were needed to satisfy internal load in January 2014, or at any time during the period under review. If so, provide the dates and duration when all sources were needed. If not, provide the sources (Rockport unit 1, Rockport unit 2, Mitchell unit 1, Mitchell unit 2, Big Sandy 1, and Big Sandy 2) that were needed to satisfy internal load and state whether the remaining sources of power were purchased or generated solely to make off-system sales.

3) The fourth paragraph makes reference to the AEP Interconnection Agreement. Given that the Interconnection Agreement is no longer in effect and, as stated in the response to Item 28, Kentucky Power is allowed to keep off-system sales margins in excess of those included in base rates as part of the Settlement Agreement in Case No. 2012-00578,(Footnote 4) explain why it is reasonable for internal load customers to pay 100 percent of "no load costs."

c. Refer to the response to Item 29.e. Provide the amount, by month, that would have been allocated to internal-load customers if "no load costs" had followed the allocation of all other fuel costs.

d. Refer to Attachment 1 filed in response to Item 29. State whether Big Sandy was needed to serve internal load during March and April 2014. If not, explain the MWhs allocated to internal load from the Big Sandy units shown on this page.

e. Refer to Attachment 2 filed in response to Item 29. Explain why Rockport "no load costs" are allocated to Kentucky Power native load customers when Kentucky Power does not own the Rockport units.

RESPONSE

a. For the cost reconstruction, other variable costs are included in the "no load" costs, including fuel handling, chemicals/consumables, emission allowances and variable operation and maintenance expenses. These costs are subsequently removed from the FAC calculation and do not flow through the FAC.

b. 1) The Company's units are generating energy when no load costs are incurred.

The Company uses a "top down" approach above the unit minimums to assign the highest cost generation to OSS. As a result, the remaining generation costs of each unit at the unit minimums, which includes the no load costs and other incremental cost between the no load cost and the unit minimum, remains with internal load.

In the event that the sum of the unit minimums exceeds KPCo's internal load, the sum of all of the units remaining costs, excluding the no load costs, is computed on a $/MWh basis, and this cost is assigned to the MWhs of any remaining off-system sales. The remainder of these costs are allocated to internal load.

The statements "no load" costs are not associated with specific increments of generation, and "no load" costs do not change when generation is increased or decreased, [and hence] economic dispatch does not provide a basis for allocation of "no load" costs, reflect the fact that "no load" costs are unchanged whether the units generate one kWh or 500 MWh above the unit minimums.

b. 2. i) Please refer to KPSC 2-4 Attachment 1.

b. 2.ii) The dispatch order of KPCo's units is not constant. In reality, it can and does vary by MW and by hour across the units. The reasons are many. First, each unit's fuel and other variable costs can change over time. Further, the heat rates of the units are not a constant, but take the form of a heat rate input/output curve that is a quadratic equation for each unit and has coefficients that change depending on water inlet temperatures. Such curves are also modified by an additional factor to synchronize with the latest testing data for the unit. As such, while units can be discussed in terms of a nominal heat rate or average $/MWh fuel cost, the settlement systems utilized by the Company create a much more refined view for terms of assigning costs.

With these explanations, please refer to KPSC 2-4 Attachment 2 for the average dispatch order of each unit for each month of the review period.

b. 2.iii) All six of the identified resources, were <u>available</u> to satisfy a portion of the Company's load during the review period, and since the minimum generation of each unit, when it is on-line, is assigned to internal load, then all of these resources were not only available for, but used to serve, the internal load of the Company. The internal load received the cheapest generation of each these six resources to serve internal load between the minimums and the maximums, and only the most expensive dispatchable generation was used to serve off-system sales.

As such, no resource was ever used in any hour to "solely make off system sales" and the Company's internal load customers always received some portion of each unit's cost and MWh output in each hour the unit was in parallel operation with the grid.

b.3. Please see the Company's response to KPSC 2-3. The period of overlap of the joint ownership and operation of Big Sandy Unit 2 and a fifty percent undivided interest in the Mitchell generating station, and the period of allocation of 100% of OSS margins to the Company, will exist for no more than approximately 17 months. It is neither reasonable nor appropriate to change an existing 30 year method of allocating "no load" costs during this interim.

c. Please see KPSC 2-4 Attachment 3. For the reasons stated in the Company's response to KPSC 1-29, KPSC 2-3, and KPSC 2-4(b) (iii), the allocation illustrated on KPSC_2_4Attachment 3 is neither reasonable nor appropriate.

Further, the allocation illustrated in KPSC 2-4 Attachment 3 would have the effect of depriving the Company of the 100% of OSS margins it is entitled to retain under the Settlement Agreement in Case No. 2012-00578. In that case, Kentucky Power agreed to limit its recovery of Mitchell-related costs (other than fuel) to $44 million a year for the period between the Mitchell transfer and the effecting date of its new base rates. This limited recovery, which is below that which would be otherwise required if full Mitchell-related costs were in rates, was agreed to by the Company in return for the ability to receive 100% of OSS margins. The Company, thus assumed 100% of the risk that OSS margins would fail to exceed the $15.3 million in base rates (In addition, customers were protected from bearing their allocated share of any short fall in OSS margin below the $15.3 million in base rates). The allocation illustrated in Staff 2-4 Attachment 3 would unfairly increase the risk assumed by the Company by retroactively "clawing back" a portion of the OSS margins that are to be used to offset a portion of the revenue shortfall resulting from the $44 million limitation.

d. Big Sandy was needed to serve internal load during March and April of 2014.

e. While Kentucky Power does not own the Rockport units, Kentucky Power has the exclusive right under the unit power agreement to its contract share of the Rockport units, and like its owned generation, the Company's contract share was procured and is available to serve Kentucky Power's internal customers. As such, Kentucky Power's share of the Rockport units provides service to Kentucky Power's internal customers in the same way that the Company's owned units do. Accordingly, it is appropriate for the Company to allocate Kentucky Power's share of the no-load costs for the Rockport units to its internal load customers in the same manner that the Company allocates the no-load costs for its owned units.

WITNESS: Kelly D Pearce

Kentucky Power Company

REQUEST

Refer to the response to Item 33.e.

a. State whether the Commission was informed in Case No. 2012-00578 of the change in accounting treatment that would be required at the Big Sandy Plant as a result of the Mitchell plant transfer. If not, explain.

b. State whether there are any other required changes in accounting treatment as a result of the Mitchell plant asset transfer. If so, explain.

c. Provide the type of meter, measuring equipment, or associated device used at the generating units to determine the number of tons consumed each month and how often these devices are tested for accuracy.

d. The response states that the internal accounting policy regarding coal pile adjustments was formally adopted in August 2014 and was effective January 1, 2014. Provide all internal communications, both written and electronic, since January 1, 2013, discussing this internal accounting policy change and state whether this accounting policy change was made as a result of Commission Staffs questions regarding the Mitchell coal pile adjustment that were asked at the June 26, 2014 meeting held at the Commission's office.

RESPONSE

a. No, the change in accounting treatment for Big Sandy was not discussed during Case No. 2012-00578.

b. The Company is not aware of other required changes in accounting treatment as a result of the Mitchell plant asset transfer.

c. The following scales are used at AEP – Mitchell Plant to weigh coal being removed from stockpiles, and sent to the unit silos:

1. 4-East Coal Scale – This scale weighs the low sulfur coal being sent to the Unit One silos. Routine calibrations are conducted on this scale once per month. This scale is material weight tested during major Unit One outages. The scale consists of load cells, a Thermo-Ramsey Model 2301-D digitizer, and a Thermo-Ramsey Micro-Tech 2000 integrator.

2. 4-West Coal Scale – This scale weights the low sulfur coal being sent to the Unit Two silos. Routine calibrations are conducted on this scale once per month. This scale is material weigh tested during major Unit One outages. The scale consists of load cells, a Thermo-Ramsey Model 2301-D digitizer, and a Thermo-Ramsey Micro-Tech 2000 integrator.

3. 3A Coal Scale – This scale weighs the blended (high and low sulfur) coal being sent to the Unit Two silos. Routine calibrations are conducted on this scale once per month. This scale is material weigh tested during major Unit One outages. The scale consists of load cells, a Thermo-Ramsey Model 2301-D digitizer, and a Thermo-Ramsey Micro-Tech 2000 integrator.

4. 3B Coal Scale – This scale weighs the blended (high and low sulfur) coal being sent to the Unit One silos. Routine calibrations are conducted on this scale once per month. This scale is material weigh tested during major Unit One outages. The scale consists of load cells, a Thermo-Ramsey Model 2301-D digitizer, and a Thermo-Ramsey Micro-Tech 2000 integrator.

d. The change to internal accounting policy was not made as a result of the Commission Staff's questions regarding the Mitchell coal pile adjustment.

Most of the discussions surrounding the change were verbal. Written communications concerning the accounting treatment is attached to this response as KPSC 2-5 Attachment 1.

WITNESS: John A Rogness