VERIFICATION

STATE OF NORTH CAROLINA)
) **SS:**
COUNTY OF MECKLENBURG)

The undersigned, John D. Swez, Director of General Dispatch & Operations, Power Trading and Dispatch, being duly sworn, deposes and says that he has personal knowledge of the matters set forth in the foregoing data requests, and that the answers contained therein are true and correct to the best of his knowledge, information and belief.

John D. Swez, Affiant

Subscribed and sworn to before me by John D. Swez on this 13 day of October, 2014.

CHRISTOPHER LEE HAMRICK

UNION COUNTY, NORTH CAROLINA

Christopher Lee Hamrick
NOTARY PUBLIC

My Commission Expires:

My Commission Expires October 24, 2014

VERIFICATION

STATE OF OHIO)
) **SS:**
COUNTY OF HAMILTON)

The undersigned, Lisa D. Steinkuhl, Lead Rates Analyst, OH/KY Rate Recovery & Analysis, being duly sworn, deposes and says that she has personal knowledge of the matters set forth in the foregoing data requests, and that the answers contained therein are true and correct to the best of her knowledge, information and belief.

Lisa D Steinkuhl

Lisa D. Steinkuhl, Affiant

Subscribed and sworn to before me by Lisa D. Steinkuhl on this 15th day of October, 2014.

Anita M. Schafer

NOTARY PUBLIC

My Commission Expires:

NOTARY PUBLIC STATE OF OHIO

ANITA M. SCHAFER
Notary Public, State of Ohio
My Commission Expires
November 4, 2014

VERIFICATION

STATE OF NORTH CAROLINA)
) **SS:**
COUNTY OF MECKLENBURG)

The undersigned, Scott Burnside, Manager of Post Analysis & Regulatory Support, being duly sworn, deposes and says that he has personal knowledge of the matters set forth in the foregoing data requests, and that the answers contained therein are true and correct to the best of his knowledge, information and belief..

Scott Burnside

Scott Burnside, Affiant

Subscribed and sworn to before me by Scott Burnside on this 20th day of October, 2014.

Katie Jamieson

NOTARY PUBLIC

My Commission Expires: June 14, 2016

KATIE JAMIESON
Notary Public
Mecklenburg County
NORTH CAROLINA

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Duke Energy Kentucky
Case No. 2014-00229
Staff Third Set Data Requests
Date Received: October 10, 2014

STAFF-DR-03-001

REQUEST:

Refer to Duke Kentucky's response to Item 1.b.(3) of Commission Staff's Second Request for Information ("Staff's Second Request"). The responses states, "Please see Confidential table below for a summary of the difference in fuel costs that would have been recovered through the fuel adjustment clause ("FAC") had the commitments in the financially binding day-ahead market not been modeled." It is unclear whether the table that appears in the response is complete. Duke Kentucky did not file a motion requesting confidentiality, nor did it file a version for which it requested confidentiality.

a. State whether the table that appears in the response is complete.
b. Explain what the amounts in the column represent. For example, state whether the $236 shown for April 2013 means that $236 more dollars were allocated to native load fuel costs than would have been allocated to native load fuel costs if the commitment in the day-ahead market to non-native load was ignored.

RESPONSE:

a. The table that appears in the response is complete. The word "Confidential" was inadvertently included in the response. The table is not confidential and is complete.
b. The amounts in the table represent the difference in the total fuel costs recovered in the FAC if the commitments in the financially binding day-ahead market are ignored and generation is re-allocated based solely upon the real-time energy market dispatch. If the

day-ahead commitments are ignored and generation is reallocated solely based upon real-time, the purchased power amount would have been lower and the fuel consumed would have been higher in the FAC during that particular period. The net impact to the FAC filing would have been a decrease in the total costs recovered of $422,784, the total of the table. The Company does not agree that the modeling solely based upon real-time reflects the accurate operation of the PJM markets under FERC-approved tariffs. Modeling solely based upon real-time does not present the entire picture of costs and benefits to Duke Energy Kentucky's customers. Moreover, modeling based solely upon real-time ignores the fact that there are must-offer obligations and binding commitments of generation in the day-ahead energy market. Further, the table showing the modeling change does not factor in the impact or the results of the day-ahead and real-time off-system sales that were accounted for and shared with customers in the PSM. The Company has not performed this re-calculation of the results of margins already shared with customers through the PSM in the aforementioned schedule but the result would have necessarily been a reduction in the margin shared with customers. Therefore, while the impact to the FAC is $422,784, the net impact to the ratepayer of the modeling change would be lower due to the reduction in the margin of off-system sales.

Additionally, it is noteworthy that the impact of this period's re-modeling was neither typical nor representative of prior periods. The majority of the impact, $404,367, occurred in January and February 2014, and was due to the extreme weather events during that period of time. The balance of the FAC impact described above, $18,917, occurred over the remainder of the 16 month period. Due to the historic cold temperatures in January and February 2014, it caused unprecedented events at PJM. In particular, it caused the Company's Woodsdale generating units to receive day-ahead awards. Under normal operating circumstances there isn't a significant deviation in the modeling and the impacts are minimal.

PERSON RESPONSIBLE: Lisa Steinkuhl / Scott Burnside

Duke Energy Kentucky
Case No. 2014-00229
Staff Third Set Data Requests
Date Received: October 10, 2014

STAFF-DR-03-002

REQUEST:

Refer to Duke Kentucky's response to Item 2 of Staff's Second Request.

a. Refer to the response to 2.e. In the response Duke Kentucky acknowledges that "[t]he guidance provided by the Commission indicates that the cost of purchased power is limited to the fuel cost of the <u>utility's</u> highest cost of generation available to be dispatched" [emphasis added], but that "[t]he displaced higher cost of generation could be virtually any generating unit in the PJM market; including the Company's and consequently, all MWhs purchased either for planned outages or when not experiencing a planned outage but are made to meet load, should be eligible for recovery and not limited by that provision."

    1. Has the Commission, through issuance of an Order, determined that Duke Kentucky's owned highest-cost generation unit should not be used as the limit for recovery through the FAC? If so, provide the case number and date of the Order. If not, explain the basis for Duke Kentucky's decision to not use its own highest-cost generation unit as the limit for recovery through the FAC.

    2. Explain whether Duke Kentucky believes that the FAC regulation should be applied to utilities that are members of a regional transmission organization ("RTO") in a manner other than how it is applied to those that are not members of an RTO.

b. Refer to the response to Item 2.f. Duke Kentucky did not provide the dollar amount of power purchases that would have been included in the calculation of the FAC if recovery of power purchases made during a planned outage had been limited to the cost of Duke Kentucky's highest-cost generating unit available. Duke Kentucky stated that 'it is impossible to determine which of the Company's units, at any given hour, would have been the highest cost in PJM . . . . . "Provide the information requested based on the fuel costs of Duke Kentucky's highest-cost generating unit that was available to be dispatched during the month.

c. Refer to the response to Item 2.g. Duke Kentucky did not provide the dollar amount of power purchases that would have been included in the calculation of the FAC if recovery of power purchases made to meet load when Duke Kentucky's highest-cost generating unit available. Duke Kentucky stated that "it is impossible to determine which of the Company's units, at any given hour, would have been the highest cost in PJM . . . . :" Provide the information requested based on the fuel costs of Duke Kentucky's highest-cost generating unit that was available to be dispatched during the month.

RESPONSE:

a) Please see responses below:

1) Duke Energy Kentucky is unaware of a Commission finding that Duke Energy Kentucky's recovery of fuel costs should be limited to the highest cost unit on its system. In Case No. 2006-00172, the Commission approved a settlement that provided in part that "Duke Kentucky will credit through its FAC make-whole revenues received from the Midwest Independent System Operators (n/k/a

Midcontinent), Inc. ("MISO"), as well as corresponding expenses, which relate to Duke Kentucky's dispatching of its generating units out-of-merit at MISO's request."

If Duke Energy Kentucky's recovery of economy power purchases was limited to its own internal highest-cost generator, the Company's operation must significantly change to the detriment of customers as customers would lose some of the very economic and reliability benefits of PJM membership that are obtained through the operation of PJM's energy markets via security constrained economic dispatch and commitment throughout the RTO footprint, not to mention the maintaining reliability of the entire system.

If Duke Energy Kentucky were required to ensure that its cost of purchase power never fluctuated above the price of its highest cost off-line generating unit to fully recover its costs, then Duke Energy Kentucky would need to self-commit its own Woodsdale peaking generating units every time its base load generation was insufficient to satisfy demand (*e.g.,* due to an outage or being fully dispatched), irrespective of market prices and prior to PJM committing the Woodsdale resources through economic dispatch, even if, after the fact, due to volatility of LMP's in the PJM market, the units actually cost more than purchases would have cost from PJM. PJM has complete information regarding the operation of its day-ahead and real-time energy markets in making the determination to commit and dispatch a unit. The Company doesn't have access to the same market information.

If the Company were to self-commit its generation in PJM, Duke Energy Kentucky would have to forecast the LMP price, the amount of purchase power forecast to be needed, and the length of time and amortization of start-up costs of the

Woodsdale units for the given time period, all potentially resulting in inefficiencies in the market and additional costs to the customer, essentially taking the company out of the day-ahead and real-time energy markets. A number of factors, many outside of the Company's control, could end up making the decision to commit the Woodsdale units to be uneconomic, including the fact the forecasted amount of native load could be less than expected or LMP's could materialize less than expected and thus the unit would end up being needed for a shorter duration than expected. Additionally, not following PJM's security constrained economic dispatch process and instead making the decision to commit the Woodsdale unit on its own, the Company, and its customers, would no longer be eligible to receive a Balancing Operating Reserve credit from PJM.

Under current PJM participation, the Woodsdale units, due to their nature as simple cycle peaking resources, have various operational limitations not present in a base load coal-fired generator, and are frequently not dispatched at times when the Company purchases power from PJM. LMP prices change every 5-minutes within the same hour and sometimes spike within an hour such that the hour itself may integrate above or below the cost of a Woodsdale unit. Therefore, there are times even within an hour where a unit may not be economic, is not dispatched by PJM and power is purchased, but then due to LMP volatility, the unit may, after the fact, appear to have been economic depending upon the settlement of the final hourly LMP price.

There are other problems with limiting purchase power recovery within PJM (or any RTO) to the utilities highest cost generating unit. There are factors that may limit a unit dispatch decision by PJM that are beyond the utility's control, but nonetheless provide benefits to customers. For example there are times that PJM will not allow certain units to run, despite appearing to be economic, due to grid reliability reasons (*e.g.* congestion).

Finally, at times when there is insufficient Company-owned generation to meet customer load/demand, the only options available to meet load obligations are to purchase from the market, use available demand response to reduce load, or to invoke blackouts to reduce demand. In this circumstance, there is no generating unit, owned by Duke Energy Kentucky, "available" to meet its load obligations. For reliability purposes the Company must purchase from the market and it does so via the PJM markets at the most 'economically' priced energy available in the RTO. It should also be pointed out that at times, even though a unit is not producing energy, that unit may be already providing off-line ancillary services, or if on-line and not fully loaded, could be providing on-line ancillary services. Thus, the assumption that the unit could have provided energy is not valid in all cases since it was already being utilized for ancillary services. The customer has already received credit from PJM for the unit through the provision of ancillary services and assuming that the unit could provide both, in many circumstances, is not possible.

2) Duke Energy Kentucky believes the FAC regulation is adequate in its current form with effect given to the plain meaning of the words in that regulation. The rule has no provision about a limit on recovering economy purchases to the highest cost 'available' generation. The application of the FAC regulation should not be so rigid as to completely ignore, erode or undermine the benefits of participation in an RTO.

There are distinctions between utilities that are participating in an RTO from those that are not due to that fact that (1) outside an RTO, prices paid for conventional bi-lateral transactions are typically known prior to entering into that transaction whereas the final price of purchase power made from an RTO via LMP is not known until the hour is over or even the next day and that LMP's can be volatile, and (2) a utility outside of an RTO retains the functional control to commit and dispatch its generating units, whereas the RTO, like PJM, uses security constrained economic dispatch and commitment of all generation within its footprint to provide the broadest and most efficient management of the entire RTO footprint. Even outside an RTO, there are still assumptions that have to be made, namely the length of time that a unit is projected to run so that its anticipated start-up cost can be amortized over the appropriate number of hours, which will impact the overall cost of dispatch. In addition, since a utility outside of an RTO may still purchase energy from an RTO, due to LMP volatility, this purchased power restriction may limit or discourage the external utility from purchasing economic energy from the RTO.

Duke Energy Kentucky does not believe that a limitation of purchase power defined by the utility's highest cost generator should be applied to a utilities energy purchases that are the result of participation inside an RTO because of the nature of the RTO's security constrained economic dispatch and commitment under FERC-approved tariffs. The RTO, in this case PJM, performs a security constrained economic dispatch and commitment, meeting system demand reliability while minimizing production costs across the entire RTO footprint.

Finally, there should be no disallowance of recovery for economic purchased power at times when the Company has insufficient generation to meet load (excluding the capacity that may be offline due to forced outages) as there is no other owned generation 'available' to meet the load obligation. It is unlikely the Commission intended that utilities incur costs necessary to meet its load obligation without allowing recovery.

b) Objection. This request is overbroad, vague and calls for speculation. At times throughout a year there may be periods where there is insufficient company owned generation 'available' to meet customer demand. This could be caused by scheduled outages, forced outages, or spikes in customer load. Without waiving said objection, in hours where there was sufficient company owned generation available greater than the amount of purchase energy and purchases occurred due to a scheduled outage, the following assumptions were made to perform this calculation; (1) to avoid complicated unit commitment cost allocation issues associated with coal units, plus due to the fact that Duke Energy Kentucky's coal units are low cost and almost always economic to run, commitment of these units were ignored for this analysis and the analysis was restricted to Woodsdale generating units, (2) start-up costs for Woodsdale units were amortized over the units one hour minimum run time for each hour, (3) the full load average cost for a Woodsdale unit was used in addition to the aforementioned startup cost and (4) it was assumed that Woodsdale station was staffed 24 hours per day, 7 days per week.

In addition, there are also other physical restrictions, such as the number of start-ups allowed per day and the minimum run time that had to be ignored for this analysis, but in reality, are real physical parameters of the units that must be considered when running the units. Finally, the fact that the units may have already been providing ancillary services, as described in 1), was ignored.

There were no instances in the period of November 1, 2012 through April 30, 2014 where Duke Energy Kentucky purchased power at the same time as a planned outage and the cost of the purchased power exceeded the cost of running one or more Woodsdale units per the calculation method described above. Planned outages typically occur during shoulder months when purchased power costs tend to be lower. The monthly amount of purchased power that would have been included is shown below. Note that these are the same monthly amounts as shown in the response to Staff-DR-02-002, f. Thus, there were no changes.

	Purchased Power for Scheduled Outages
November-12	$0
December-12	$75,062
January-13	$418,704
February-13	$0
March-13	$0
April-13	$4,763,663
May-13	$0
June-13	$570,555
July-13	$1,732,276
August-13	$103,561
September-13	$0
October-13	$0
November-13	$0
December-13	$0
January-14	$0
February-14	$0
March-14	$9,597,837
April-14	$8,000,046

c) Objection. This request is overbroad, vague and calls for speculation. Without waiving said objection, at times throughout a year there may be periods where there is insufficient company owned generation 'available' to meet customer demand. This could be caused by scheduled outages, forced outages, or spikes in customer load. The only options available during these times are to purchase power from the market, engage demand response or load shedding blackouts. In hours where Duke Energy Kentucky had insufficient generation 'available' to meet its load but was not caused by a forced or scheduled outage, by definition, there could be no 'available' generation, owned by Duke Energy Kentucky to measure economy purchases against. At those times, all 'available' Duke Energy Kentucky owned generation would be operating but insufficient to meet its load. The standard of limiting recovery for such purchased energy to the cost of 'available' generation would therefore be moot.

Even though there were no actual units available that could have been run, the cost of a Woodsdale unit was utilized to perform this analysis with the same assumptions utilized in part b) above. During the period of November 1, 2012 through April 30, 2014 there was a single hour in July of 2013 where PJM dispatched every one of Duke Energy Kentucky's available generating units, the amount of generation was insufficient to meet load requirements, and the cost of purchased power exceeded the cost of running all six Woodsdale units per the calculation described above. The cost of purchased power in this hour was $11,787 greater than the cost would have been if additional Woodsdale units existed and could have been utilized in lieu of purchasing power. The monthly amount of purchased power that would have been included is shown below. Note that the amount for the month of July 2013 was reduced by $11,787. Other than this change, these are the same monthly amounts as shown in the response to Staff-DR-02-002, f.

	Purchase Power
November-12	$119,454
December-12	$202,755
January-13	$379,788
February-13	$270,172
March-13	$148,752
April-13	$139,001
May-13	$461,050
June-13	$1,252,615
July-13	$2,464,592
August-13	$1,751,566
September-13	$974,175
October-13	$101,222
November-13	$51,374
December-13	$536,351
January-14	$5,744,691
February-14	$1,719,457
March-14	$31,421
April-14	$0

PERSON RESPONSIBLE: John Swez/ Scott Burnside