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October 3, 2006

HAND DELIVERED

Beth O'Donnell
Executive Director
Public Service Commission of Kentucky
211 Sower Boulevard
P.O. Box 615
Frankfort, Kentucky 40602-0615

RECEIVED

OCT 03 2006

**PUBLIC SERVICE
COMMISSION**

Michele M. Whittington
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RE: Kentucky Power Company
PSC Case No. 2006-00307

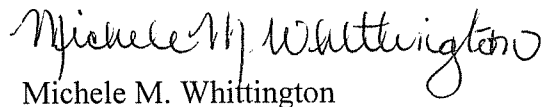
Dear Ms. O'Donnell:

Enclosed please find and accept for filing the original and five (5) copies of Kentucky Power Company's Responses to the Commission's September 21, 2006 Second Set of Data Requests. By copy of this letter, copies are being served on KIUC and the Attorney General.

If you have any questions, please feel free to contact me.

Sincerely,

STITES & HARBISON, PLLC


Michele M. Whittington

MMW/las

Enclosures

cc: Elizabeth E. Blackford
Michael L. Kurtz

KE057:KE113:14791:1:FRANKFORT

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OCT 03 2006
PUBLIC SERVICE
COMMISSION

COMMONWEALTH OF KENTUCKY
BEFORE THE
PUBLIC SERVICE COMMISSION OF KENTUCKY

IN THE MATTER OF

THE APPLICATION FOR KENTUCKY POWER COMPANY)
FOR APPROVAL OF AN AMENDED COMPLIANCE)
PLAN FOR PURPOSES OF RECOVERING ADDITIONAL) CASE NO. 2006-00307
COSTS OF POLLUTION CONTROL FACILITIES AND)
TO AMEND ITS ENVIRONMENTAL COST RECOVERY)
SURCHARGE TARIFF)

KENTUCKY POWER COMPANY RESPONSES TO
COMMISSION SECOND SET DATA REQUEST

October 3, 2006

Kentucky Power Company

REQUEST

Refer to the response to the Staff's First Data Request dated August 24, 2006 ("Staff's First Request"), Item 2(a). Concerning the multi-emissions compliance optimization ("MECO") model:

- a. Kentucky Power indicates that the MECO model was developed as part of an Electric Power Research Institute tailored collaboration project. Explain what is meant by the phrase "tailored collaboration project."
- b. Kentucky Power states that, "The AEP MECO model is not available to the rest of the electric industry." Is a non-American Electric Power Company ("AEP") specific version of MECO available to the electric industry? Explain the response.

RESPONSE

1a) A Tailored Collaboration (TC) allows EPRI members to provide supplemental funds (over and above their membership payments), which are matched on a one-to-one basis by EPRI with funds held in a TC pool. A portion of an EPRI member's base payments are set aside in the TC pool to use for member-selected scientific research and certain technology application projects within programs that are of particular importance to the member. The development of the MECO model occurred as a TC project.

1b) A non-AEP specific version of the model is available for purchase through CRA International and is referred to as the National Energy and Environment Model (NEEM). The MECO model is unique in that the model structure and input file have been customized to allow for a more accurate projection of AEP's least cost compliance strategy than the stock version of NEEM.

WITNESS: John M McManus

Kentucky Power Company

REQUEST

Refer to the response to the Staff's First Request, Item 6.

- a. Would Kentucky Power agree that the processes contained in the gas desulfurization equipment ("scrubber") that remove sulfur dioxide ("SO₂") from a generating station's emissions will accomplish the reduction regardless of the sulfur mix in the coal burned? Explain the response.
- b. If there is a full operational scrubber on a generating station removing SO₂, to what extent does the existence or absence of coal blending facilities impact the generating station's ability to comply with the requirements of Title IV, 40 CFR 72-78 and the Clean Air Interstate Rule, 40 CFR96? Explain the response.

RESPONSE

2a) Kentucky Power agrees that flue gas desulfurization equipment ("scrubbers") will achieve *some* level of sulfur dioxide reduction regardless of the sulfur mix in the coal burned. However, once installed and operational, the existence of this control equipment provides the opportunity to cost-optimize sulfur dioxide removal and fuel selection. Because the equipment functions well over a wide range of eastern bituminous coals, AEP has included fuel flexibility and cost savings in its cost-benefit analysis of its compliance program.

2b) Because Title IV and the Clean Air Interstate Rule are market-based programs, AEP has planned its compliance program to take advantage of the most cost-effective reductions. The existence of fuel blending facilities at certain of the AEP generating stations will provide the most cost-effective compliance plan by allowing these generating stations to accept a wider variety of coals with varying fuel characteristics, and still perform reliably. As noted in the response to Staff's First Request, Item 6(a), the coal blending projects would not be undertaken absent the requirement to comply with current and future regulations under Title IV, 40 CFR 72-78 and the CAIR Program, 40 CFR 96.

WITNESS: John M McManus

Kentucky Power Company

REQUEST

Refer to the response to the Staff's First Request, Item 9(e).

- a. Based on the response to Item 9(e), would Kentucky Power agree that for the six generating stations shown on page 3 of 62, AEP cannot determine whether there has been, or is expected to be, a significant increase in the emission of sulfuric acid ("H₂SO₄") as a result of installing scrubbers or Selective Catalytic Reduction equipment ("SCR")? Explain the response.
- b. The results shown in the table on page 3 of 62 are stated in "ppmdv." Convert the results into the equivalent amounts of tons per year and provide the workpapers showing the conversion.
- c. Explain why it is reasonable to assume all of the sulfur trioxide ("SO₃") in the flue gases will be converted to H₂SO₄ prior to exiting the stack.
- d. If AEP does not have the SO₃ and H₂SO₄ emission data for any time periods prior to the installation of scrubbers and SCRs, how can it accurately determine whether there has been a significant increase in the release of H₂SO₄? Explain the response.

RESPONSE

3a) No. Based on the response to Item 9(e), no "significant net increase" in emissions of sulfuric acid will occur as a result of completing the installation of the scrubbers and SCRs (including the SO₃ mitigation facilities) at the six generating units shown on page 3 of 62, that would trigger the requirement for a new source review permit. As noted in the original response, extensive testing has been performed at Ohio Power Company's Gavin Plant to evaluate the formation, conversion, and removal of SO₃/H₂SO₄ at various locations in the steam generator, before and after the SCR systems, before and after the FGD systems, and before and after the mitigation systems. This testing has allowed AEP to develop the most cost-effective systems for controlling the formation of SO₃/H₂SO₄ and removing SO₃/H₂SO₄ from the flue gas, including measures like the low conversion SCR catalysts and sorbent injection systems included in this filing. With these measures in place, no "significant net increase" in sulfuric acid emissions will occur as a result of the installation of the scrubbers and SCRs.

3b) The test results shown in the table represent SO₃/H₂SO₄ concentrations measured during a specific time period under specific operating conditions. A concentration expressed as ppm_{dv} is a dimensionless concentration that is expressed as “volumetric parts per million volumetric parts”. The parts can be liters (i.e. liters per million liters), cubic centimeters (i.e. cubic centimeters per million cubic centimeters) or any other chosen volumetric measure. In order to convert these “point in time” ppm_{dv} values to ton per year values, we would have to make a large number of assumptions concerning annual operations. These include, but are not limited to, assumptions related to the concentration variability of the pollutant in the flue gas, and the total amount of flue gas discharged during the year. Naturally, the amount of flue gas discharged during the year is proportional to the utilization of the generating units.

While it is not meaningful to convert the specific “point in time” concentrations to an annual pollutant emissions figure given the number of assumptions that would have to be made, it could be useful to show how the ppm_{dv} concentration relates to actual emissions on a short term basis.

Following are some sample calculations:

For a typical wet-scrubbed 1300 MW generating unit (Amos Unit 3 and Gavin Units 1&2 are 1300 MW units) with a full load flue gas flow rate of approximately 4.2E6 actual cubic feet per minute (acfm), a 5 ppm_{dv} change in H₂SO₄ stack concentrations equates to approximately a 203 lb/hour change in H₂SO₄ emissions. The calculation is shown below.

Basis: Change in H₂SO₄ Concentration = 5 ppm_{dv}
Molecular Weight of H₂SO₄ = 98.07 g/mole (98.07 µg/µmole)
Flue Gas Temperature = 130 °F (327.6 °K)
Flue Gas Pressure = 760 mmHg
Flue Gas Flow = 4.2E6 acfm (7.14E6 actual cubic meters per hour)
At standard temperature and pressure, one mole of any gas occupies 24.46 L

Convert 5 ppm_{dv} to wet basis and 6% O₂:
(5 ppm_{dv}) x (1-0.15) x ((20.9 – 6)/(20.9 – 3)) = 3.54 ppm_v(wet, 15%) at 6% O₂ = 3.54 µL/L

At 327.6 °K and 760 mmHg, one mole of gas occupies...

$$(24.46 \text{ L}) \times (327.6 \text{ °K}/298 \text{ °K}) \times (760 \text{ mmHg}/760 \text{ mmHg}) = 26.89 \text{ L}$$

* Since 1 mole of gas occupies 26.89 L, it stands to reason that 1 µmole of gas occupies 26.89 µL

Accordingly a 3.54 ppm_v (3.54 µL/L) change equates to the following lb/hour change:

$$(3.54 \text{ µL/L}) \times (1 \text{ µmole}/26.89 \text{ µL}) \times (98.07 \text{ µg/µmole}) \times (1,000 \text{ L/m}^3) \times (7.14\text{E}6 \text{ m}^3/\text{hr}) \times (1 \text{ lb}/4.54\text{E}8 \text{ µg})$$

$$= 203 \text{ lb H}_2\text{SO}_4/\text{hour}$$

As such, less than 70 hours (there are 8,760 hours per year) of full load operation per year under a 5 ppmvd relative change in H₂SO₄ concentration would result in an approximate 7 ton per year H₂SO₄ increase. While smaller generating units or smaller relative changes in H₂SO₄ concentrations would result in longer periods of time before the 7 ton per year threshold is reached, it is nevertheless obvious that at least a 7 ton increase would occur over a one year period without an SO₃ mitigation system in place.

3c) SO₃ is hygroscopic and, therefore, absorbs vapor phase moisture at temperatures above its dew point to form H₂SO₄. While combustion temperatures are extremely high, as the combustion gases move through a wet FGD process, the flue gas becomes saturated with moisture and drops to temperatures well below the dew point of H₂SO₄ vapor, averaging about 130°F when the saturated gas exits the stack. Accordingly, H₂SO₄ mist is formed before the flue gas exits the stack.

3d) Each of the six generating units shown on page 3 of 62 of Kentucky Power's response to the Staff's First Data Request are designed to utilize a coal supply resulting in at least a 4.5 lbs SO₂/mmBtu uncontrolled emission rate. As such, the uncontrolled SO₂ concentration produced from burning such a coal supply would be at least approximately 1,976 ppm, according to calculations found in 40 CFR 60 Method 19 Section 12.2. The calculation is shown below:

Basis: Pollutant Emission Rate = Cd x Fd x (20.9/(20.9 - %O₂)); where Cd = ppm x 1.660E-7
Fd = 9,780 dscf/mmBtu for Bituminous coal (from Test Method 19)
%O₂ = 6% (as used in calculation for response to question 3.b)

4.5 lb/mmBtu = (ppm x 1.660E-7)(9,780)(20.9/(20.9-6))
Therefore, ppm SO₂ = 1,976 ppmvd

Using a conservative 0.4% conversion rate for a low SO₂ to SO₃ conversion SCR catalyst, the predicted SO₃ increase caused by the SCR is approximately 7.9 ppm. In comparison, under AEP's current SCR catalyst replacement strategy, the conversion rate will vary from 0.45% to 0.6%. Even if the air pre-heater removes 20% of this newly created SO₃ and a wet FGD system will remove another 20%, then the remaining SO₃ concentration will still be approximately 5 ppm. Once an FGD system is in place, as reflected in the response to question 3(c), all of the SO₃ will be converted to H₂SO₄ prior to exiting the stack. As previously demonstrated in the response to question 3(b), even such relatively small increases in H₂SO₄ concentrations will quickly result in an increase in H₂SO₄ emissions far greater than 7 tons per year, without the use of an SO₃ mitigation system.

WITNESS: John M McManus