EAST KENTUCKY POWER COOPERATIVE

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PUBLIC SERVICE COMMISSION

June 2, 2014

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

Re: Annual Resource Assessment for East Kentucky Power Cooperative, Inc. (Administrative Case No. 387)

Dear Mr. Derouen:

Please accept this in follow-up to your letter of May 19, 2014 regarding the inadvertent omission by East Kentucky Power Cooperative, Inc. (EKPC) of the discussion of the consideration given to price elasticity in forecasted demand, energy, and reserve margin. On behalf of EKPC, I would like to sincerely apologize for this oversight. As requested, we are providing said discussion, below, as well as our updated responses to PSC Requests 7 & 8, as requested in your May 19, 2014 letter.

## Price Elasticity

EKPC considers price elasticity in all long term load forecasting and did so in its March 31, 2014 Annual Filing in Administrative Case No. 387, which included data from EKPC's *2012 Load Forecast*, which was itself approved by the EKPC Board of Directors in November 2012. An updated forecast is scheduled to be completed in late 2014 and will also include the impacts of price elasticity.

EKPC's load forecast model follows Itron's statistically-adjusted, end-use model framework, in which the price elasticity of demand is assumed rather than estimated within the model. When creating its *2012 Load Forecast*, EKPC maintained the original, vendor-supplied default assumption of -0.3 for all customer classes for all owner-member cooperatives. This implies that a 1 percent increase in the price of electricity for a given customer class of a given owner-member cooperative results in a 0.2 percent decrease in electric usage by those customers. Thus, EKPC's latest load forecast is based on the assumption that electricity demand is highly inelastic.

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While research generally confirms this (i.e., the price elasticity of demand is somewhere between -1 and 0), particularly in the short run due to the high costs associated with switching to other fuels, EKPC is aware of studies that have shown substantial variation and a wide range of uncertainty regarding the price elasticity of demand for electricity across customer classes, over time, and across states.

In 1993, "A Study of Energy Demand Elasticities in Support of the Development of the NEMS," by Carol Dahl of the Colorado School of Mines, identified the range of estimates summarized in the table below:

**Price Elasticity of Electricity Demand in the U.S.**

| Customer Class | Time Horizon | Range of Estimates | |
|---|---|---|---|
| Residential | Short Run | -0.80 | -0.00 |
| Residential | Long Run | -2.50 | -0.00 |
| Commercial | Short Run | -1.18 | -0.17 |
| Commercial | Long Run | -4.74 | -0.00 |

In the Energy Information Administration report "Price Responsiveness in the AEO2003 NEMS Residential and Commercial Buildings Sector Models," Steven H. Wade found that demand is slightly less price elastic in the commercial sector than it is in the residential sector and that demand is substantially more elastic over longer time horizons:

**Price Elasticity of Electricity Demand in the U.S. by Time Horizon**

| Customer Class | 1-Year | 2-Year | 3-Year | Long Run |
|---|---|---|---|---|
| Residential | -0.20 | -0.29 | -0.34 | -0.49 |
| Commercial | -0.10 | -0.17 | -0.20 | -0.45 |

In the 2005 RAND Corporation report "Regional Differences in the Price-Elasticity of Demand for Energy," Mark A. Bernstein and James Griffin found that demand in this area is more price elastic in the commercial sector over the long run than it is in the residential sector over the short run:

**Price Elasticity of Electricity Demand in the East South Central U.S. Census Division**

| Customer Class | Time Horizon | Coefficient | 95% Confidence Interval | |
|---|---|---|---|---|
| Residential | Short Run | -0.266 | -0.405 | -0.126 |
| Residential | Long Run | -0.618 | -0.900 | -0.336 |
| Commercial | Short Run | -0.271 | -0.507 | -0.035 |
| Commercial | Long Run | -0.995 | -2.024 | 0.033 |

Note: This division includes Kentucky, Tennessee, Alabama, and Mississippi.

As previously stated, EKPC is currently updating the load forecast and will address the uncertainty regarding the price elasticity of demand by developing sensitivity analysis.

Again, please accept my apology for omitting this discussion from the original submittal of the resource assessment. Please be assured that we have taken steps to ensure this oversight will not happen again.

If you have any further questions, please do not hesitate to contact me.

Sincerely,

Patrick C. Woods

PCW/gw

Attachment

**EAST KENTUCKY POWER COOPERATIVE, INC.**
**PSC ADMINISTRATIVE CASE NO. 387**
**ANNUAL RESOURCE ASSESSMENT FILING**

**PUBLIC SERVICE COMMISSION REQUEST DATED 12/20/01**
**REQUEST 7**
**RESPONSIBLE PERSON:** **Julia J. Tucker**
**COMPANY:** **East Kentucky Power Cooperative, Inc.**

**Request 7.** The target reserve margin currently used for planning purposes, stated as a percentage of demand. If changed from what was in use in 2001, include a detailed explanation of the change.

**Response 7.** (Original) EKPC integrated into PJM on June 1, 2013. EKPC is required to provide its pro-rated share of the PJM reserve requirements. PJM is a summer peaking system, so EKPC's reserve requirement shifted from being based on winter peak to summer peak. Additionally, EKPC's load diversity with PJM's peak period acts to reduce EKPC's net reserve requirements. Based on current conditions, EKPC carries approximately 6% reserves on its summer peak load during the first three years under the Fixed Resource Requirements ("FRR") plan. Starting on June 1, 2016, EKPC will participate in the Reliability Pricing Model ("RPM"), which will lower EKPC's resource requirements to roughly 3% of its summer peak load..

**Response 7.** (Updated) The derivation for the equivalent reserve margin was provided in Section 4.4 of the Charles River Associates report developed for EKPC for Case No. 2012-00169 and stated the following.

In PJM's RPM for the June 2014 to May 2015 delivery year, PJM targets a 15.3% installed reserve margin ("IRM") target applicable to the average of the 5 highest PJM peak load hours. Combined with a PJM-wide average equivalent forced-outage rate ("EFOR") of 6.25%, this yields an Unforced Capacity Obligation ("UCAP") requirement of 8.09%. Using annual EKPC data from 2008 to 2011, the EKPC peak during the five PJM peak hours has been only 91.2% of the actual EKPC summer peak (ranging from 89.8% to 92.5%), and the average forced-outage rate for the EKPC generating units has been 4.1%. Taking these factors into account, Charles River Associates estimated that the EKPC installed planning reserve target for EKPC's summer peak in 2014/15 would be 2.8% as a member of PJM. Maintaining this 2.8% EKPC installed reserve margin in the summer would yield the 8.09% UCAP requirement that EKPC would need in 2014/15 as a member of PJM. The effective summer installed planning reserve margin for EKPC as a member of PJM is similar in other delivery years, but varies slightly as PJM's estimate of IRM and pool-wide EFORs varies somewhat by delivery year.

During the 2013/14; 2014/15 and 2015/16 delivery years, EKPC will participate in the Fixed Resource Requirement ("FRR") plan. During the FRR period, EKPC is required to hold back an additional 3% in reserve requirements.

EKPC assumes 6% reserve requirements based on the 2.8% calculated value plus the additional 3% holdback required for FRR. The actual value is 5.8% and EKPC rounded it to 6.0% to allow for variations in assumptions.

**EAST KENTUCKY POWER COOPERATIVE, INC.**
**PSC ADMINISTRATIVE CASE NO. 387**
**ANNUAL RESOURCE ASSESSMENT FILING**

**PUBLIC SERVICE COMMISSION REQUEST DATED 12/20/01**
**REQUEST 8**
**RESPONSIBLE PERSON:** **Julia J. Tucker**
**COMPANY:** **East Kentucky Power Cooperative, Inc.**

**Request 8.** Projected reserve margins stated in megawatts and as a percentage of demand for the current year and the following 4 years. Identify projected deficits and current plans for addressing these. For each year identify the level of firm capacity purchases projected to meet native load demand.

**Response 8.** (Original) The table below shows the projected summer peak and reserve levels.

| Year | Summer Load (MW)* | Reserves (MW) | Reserves (%) |
|---|---|---|---|
| 2014 | 2337 | 371 | 16% |
| 2015 | 2368 | 340 | 14% |
| 2016 | 2402 | 306 | 13% |
| 2017 | 2436 | 272 | 11% |
| 2018 | 2467 | 241 | 10% |

* Net of Demand Response.

As indicated in the table above, there are no projected reserve deficits.

<u>**Response 8.**</u> <u>(Updated)</u> The table below shows the projected winter peak and reserve levels. EKPC is a winter peaking utility but does not currently carry reserves based on its winter peak due to PJM capacity requirements being based on summer peak only.

| Year | Winter Load (MW)* | Reserves (MW)** | Reserves (%) |
|---|---|---|---|
| 2014 | 3313 | (155) | (4.7%) |
| 2015 | 3017 | 141 | 4.7% |
| 2016 | 3056 | (48) | (1.6%) |
| 2017 | 3101 | (93) | (3.0%) |
| 2018 | 3140 | (132) | (4.2%) |

*Net of Demand Response.

** Dale Station retired on April 16, 2015.