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UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Frankfort Electric and Water Plant Board and the Cities of Barbourville, Bardstown, Bardwell, Benham, Berea, Corbin, Falmouth, Madisonville, Nicholasville, Paris, and Providence, Kentucky, Complainants v. Kentucky Utilities Co. Respondent	Docket No. EL09-____-000

COMPLAINT OF KENTUCKY MUNICIPALS

This Complaint is submitted pursuant to Federal Power Act Section 206 and 18 C.F.R. § 385.206 ("Rule 206") by the Frankfort Electric and Water Plant Board and the Cities of Barbourville, Bardstown, Bardwell, Benham, Berea, Corbin, Falmouth, Madisonville, Nicholasville, Paris, and Providence, Kentucky (hereafter "Kentucky Municipals" or "Municipals"). On September 29, 2008, in Commission Docket No. ER08-1588-000, Kentucky Utilities Company ("KU") filed under FPA Section 205 to replace existing contracts with the Kentucky Municipals to adopt formula rates for charges under the replacement contracts. Kentucky Municipals filed timely documentless interventions and subsequently filed an extensive protest in ER08-1588 ("Protest") requesting the Commission reject the filing for its violation of Commission policy and regulations, reject the filing as patently deficient, or in the alternative, summarily modify the proposed terms, conditions, and proposed formula so as to make its rate treatments just and reasonable, impose a maximum suspension, and set the proceeding for trial-type evidentiary hearing, but hold that hearing in abeyance to allow for

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Settlement Judge mediation. This Complaint seeks a related investigation and refund effective date under FPA Section 206, and asks that this third proceeding be consolidated with ER08-1588.

I. IDENTIFICATION OF COMPLAINANTS AND CONTACT INFORMATION

Each of the Kentucky Municipals owns and operates a municipal electric distribution system in Kentucky. Each of the Kentucky Municipals currently is a requirements customer and bundled transmission customer of KU. Their loads are part of KU's network load for purposes of service under the KU/LG&E OATT. Kentucky Municipal member the City of Paris, Kentucky, owns and operates approximately 12 MW of local generation.

Communications regarding these proceedings should be directed to the following:

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II. IDENTIFICATION OF RESPONDENT

KU is a public utility that owns and operates electric generation, transmission, and distribution facilities in Kentucky, with limited operations in Tennessee and Virginia. KU is a wholly-owned subsidiary of E.ON U.S. LLC ("E.ON U.S."), a Kentucky corporation and public utility holding company. E.ON U.S. is a wholly-owned subsidiary of E.ON AG ("E.ON"), a stock corporation formed under the laws of the Federal Republic of Germany.

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III. IDENTIFICATION OF ALLEGED VIOLATION AND ITS CONSEQUENCES NOT REMEDIABLE IN ANOTHER FORUM, PURSUANT TO RULES 206(B)(1)-(6)

KU's filing in ER08-1588 is patently unreasonable and anticompetitive, and contrary to both statute and contract. Many of those violations' consequences are remediable under FPA Section 205 in those dockets, but others may not be so remediable.

It is highly likely that at least some of the charges for the services that are at issue in ER08-1588 will, when reset to the updated just and reasonable level, turn out to fall below the level that were accepted in 1983 in *Kentucky Utilities Co*., 24 F.E.R.C. ¶ 61,338 (1983). That is not just a theoretical possibility. Under KU's existing rates, the Kentucky Municipals would pay approximately $90 million per year.[1] The Kentucky Municipal's Protest in ER08-1588 demonstrated that, applying the non-exhaustive, preliminary list of adjustments identified in the Protest, KU ought to have charged $82 million per year. However, under the "last clean rate" doctrine, the 1983 rates may set a floor under the potential outcome of a proceeding that is conducted solely under Section 205. A related proceeding under Section 206 is appropriate to eliminate any technical barrier to just and reasonable rate outcomes.

Resolution of Kentucky Municipals' Section 206 complaint does not require a separate paper or trial-type hearing. This complaint proceeding should be consolidated or otherwise linked with the proceedings in ER08-1588 for purposes of decision by the Commission proper, and for hearing by an Administrative Law Judge to the extent there are any issues not properly resolved summarily. Both dockets involve a common nucleus of operative facts.

A Section 206 refund effective date should be established and published. The Commission has indicated that where, as here, separate evidentiary hearings are not required

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because a congruent Section 205 rate determination is underway, the formal step of establishing a refund effective date is appropriate whenever the last clean rate may be excessive. See, e.g., *Xcel Energy Services Inc.*, 109 FERC ¶ 61, 284, P 21 (2004) (instituting Section 206 investigation where the just and reasonable rate "may be lower" than the last clean rate); see also *Maine Public Utilities Commission v. Central Maine Power Company*, 111 FERC ¶ 61,283 (2005).

IV. SPECIFIC RELIEF OR REMEDY REQUESTED, PURSUANT TO RULE 206(B)(7)

The Kentucky Municipals request the prompt establishment of a refund effective date timed to afford maximum consumer protection. Under Section 206 as amended by Section 1285 of the Energy Policy Act of 2005, the date must fall within a five-month window that opens upon "the date of the filing of such complaint," *i.e.,* today. KU's filing in ER08-1588 shows that KU may be overcharging the Kentucky Municipals by 10% or more.[2] Accordingly, the Kentucky Municipals request that the refund effective date be today, October 27, 2008.

V. SUPPORTING DOCUMENTS, PURSUANT TO RULE 206(B)(8)

A copy of the protest filed in ER08-1588-000, with its Attachments, is provided as Appendix 1.

VI. STATEMENT REGARDING ALTERNATIVE DISPUTE RESOLUTION, PURSUANT TO RULE 206(B)(9)

Because this complaint seeks to apply the to-be-adjudicated outcome of ER08-1588 while avoiding potential problems involving the last clean rate and the form of refunds, it is not

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[1] See KU Exhibit 12 in Docket No. ER08-1588, at 1 (last row, last column).

[2] If the just and reasonable amount to be collected from the Municipals is $82 million per year, then the $90 million per year (based on a 2007 test year) that the Municipals would pay is 10% excessive. If the just and reasonable rate is lower than $82 million per year – which a full investigation may reveal – then the existing rates are even more than 10% excessive.

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amenable to alternative dispute resolution on a stand-alone basis. The Kentucky Municipals' Protest did, however, request that the Commission appoint a settlement judge and convene a settlement conference in advance of any hearing so that the parties may attempt to resolve any disputes under the Commission's settlement procedures. If the Commission initiates a settlement proceeding in ER08-1588, that proceeding should encompass this new EL docket as well.

VII. CONCLUSION

For the foregoing reasons, the Kentucky Municipals ask that a Section 206 refund effective date be established and published, and that this new docket be consolidated with or otherwise linked to the ER Dockets.

Respectfully submitted,

/s/ David E. Pomper

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October 27, 2008

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Appendix 1

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UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Kentucky Utilities Co.	Docket No. ER08-1588-000

PROTEST OF KENTUCKY MUNICIPALS WITH REQUESTS FOR REJECTION, SUMMARY DISPOSITIONS, MAXIMUM SUSPENSION, AND HEARING

On September 29, 2008, Kentucky Utilities Company ("KU") filed to replace existing contracts with twelve Kentucky municipal electric systems (hereafter "Kentucky Municipals" or "Municipals") and to adopt formula rates for charges under the replacement contracts. Kentucky Municipals consist of the Frankfort Electric and Water Plant Board and the Cities of Barbourville, Bardstown, Bardwell, Benham, Berea, Corbin, Falmouth, Madisonville, Nicholasville, Paris, and Providence, Kentucky, each of which has previously joined a document-less intervention. They now present their protest and recommended dispositions of KU's filing.

I. SUMMARY

KU's filing has not been shown to be just, reasonable, and non-discriminatory. To the contrary, it is patently unreasonable and anticompetitive, and contrary to both statute and contract. Listing highlights without being exhaustive, they include (a) numerous proposals that unreasonably constrain Municipals' ability to access non-KU power in the future, (b) numerous proposals that unreasonably require Municipals to pay in advance for power they may or may not purchase in the future, and (c) numerous rates and terms that are unjust, unreasonable, or discriminatory on other grounds. And the information provided in support of these flawed proposals is likewise deficient. Highlights of the problems with the filing include:

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- A contractually barred and anticompetitive proposal to cancel the availability of the Municipals' partial requirements service option — an option that Municipals have previously successfully defended before this Commission and the U.S. Courts of Appeal. See Part II.A below.

- An attempt to resolve now that future purchases of Southeastern Power Administration ("SEPA") capacity and energy will receive no capacity credit, spoiling their economics. See Part II.B.

- An attempt to grab the Municipals' reservation priority for future use of the transmission capacity that is now being used to deliver KU's sales to the Municipals, and thereby impede the Municipals' ability to access non-KU power sources after giving due notice. See Part II.C.

- Formulaic collection of Construction Work In Progress ("CWIP"), without even attempting to fulfill the binding requirements of the CWIP filing regulation, 18 C.F.R. § 35.25. See Part II.D.

- Automatic flow-through of booked pension and benefits costs, contrary to Commission policy and inter-generational equity. See Part II.E.

- A complete absence of the Period II information that is required by the Commission's filing regulations and necessary to adequately review the proposed formula. See Part II.F.

- A formula that, contrary to decades-old Commission policy, is intended to mismatch a year-end rate base with a rate divisor based on year-long-average load. See Part II.G.

- A return on equity that appears to be 210 basis points too high. See Part II.H.

- Inadequate provision for flow-through of the green-power attributes for whose costs Municipals will automatically pay. See Part II.I.

- Contrary to recently-clarified Commission policy, a tight time bar for claims that KU improperly applied the rate formula. See Part II.J.

- Provisions requiring mandatory arbitration and forfeiting jury trial rights. See Part II.K.

- An unreasonably complete prohibition on actions needed to protect health and safety in a localized emergency. See Part II.L.

- Discriminatory treatment of local facility direct assignment. See Part II.M.

- Unreasonable provisions in the proposed interchange agreement with the City of Paris. See Part II.N.

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For the reasons set forth herein, the Commission should respond to KU's filing with the following actions or alternative[1] actions:

1. Reject it because it violates generally-applicable Commission policy and filing regulations that should not be waived.
2. Reject it as patently deficient for lack of adequate cost support.
3. Summarily modify the proposed terms and conditions, and summarily modify the proposed formula so as to make its rate treatments just and reasonable.
4. Impose a maximum suspension, of five months from the date on which the rate would otherwise go into effect, to May 1, 2009.
5. Set it for trial-type evidentiary hearing, but hold that hearing in abeyance to allow for Settlement Judge mediation.

Although KU has filed individual proposed replacement contracts for each of the twelve Municipals, those contracts follow a common template, with only one major customization. Accordingly, and following KU's convention, we cite to the proposed terms and conditions by referencing the template "Amended and Restated Agreement" ("ARA") that constitutes KU Exhibit 1, and the "Amended and Restated Interchange Agreement " ("ARIA") that is proposed for application to the City of Paris and which constitutes KU Exhibit 3.

II. PROTEST

For sales within the area at issue here, KU has market power and lacks market-based rate authorization. The rates, terms, and conditions under which it sells to Municipals must be reviewed to ensure that they are cost-based, consistent with contract obligations, and otherwise just, reasonable, nondiscriminatory, and in the public interest, and the burden is on KU to demonstrate that they do. As shown below, the filing does not meet those standards. To the

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[1] Where the listed recommended dispositions are inconsistent, the later-listed recommendation is presented in the alternative. For example, the items that involve acceptance of the filing apply only in the alternative, in case the filing is not rejected.

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contrary, as non-exhaustively quantified in Attachment 1 hereto, not only is the proposed rate increase substantially excessive, but in fact the existing rates appear to be over-recovering, such that no rate increase is warranted.

A. KU's Proposal to Cancel the Availability of Partial Requirements Service Violates Both Contract and Settled KU-Specific Precedent, and Is Anticompetitive, Unjust, Unreasonable, and Unduly Discriminatory

In "the bad old days," now-Chief-Justice Roberts has written, "utilities were vertically integrated monopolies" that generally provided all of the "electricity generation, transmission, and distribution for a particular geographic area," and "competition among utilities was not prevalent.'' *Midwest ISO Transmission Owners v. FERC,* 373 F.3d 1361 (D.C. Cir. 2004) (quoting in part *New York v. FERC,* 535 U.S. 1, 5 (2002)). Even then, however, this Commission successfully labored to maintain the potential for beneficial competition, and in particular to ensure that utilities taking requirements power service would not be unreasonably blocked from developing their own generation investments with which to serve some or all of their retail loads. This insistence on a path to ownership not only laid the foundation for today's wholesale power markets, it served as a vital check on requirements power suppliers: if their generation cost too much or was priced too high, or if a supplier otherwise became an undesirable business partner, wholesale requirements customers would have a practical route to growing, incrementally, into substantially or entirely self-sufficient utilities.

In natural gas regulation, this policy was codified in the Order No. 436 rulemaking, where the Commission struck down "sole supplier" clauses and required pipelines to "modify any existing contract terms that would prevent" customers from "making use of the rule's [open

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access] transportation services."[2] In electricity regulation, one of the leading applications of this policy has been the Commission's insistence that Kentucky Utilities keep partial requirements service available to Kentucky municipals. See *Ky Utils. Co.,* Opinion No. 169, 23 F.E.R.C. ¶ 61,317 (1983) (addressing exceptions to Initial Decision reported at 10 F.E.R.C. ¶ 63,057 (1980)), *on reh'g,* Opinion No. 169-A, 25 F.E.R.C. ¶ 61,205 (1983), *aff'd in relevant part and remanded as to notice period sub nom. Ky. Utils. Co. v. FERC* 766 F.2d 239 (6th Cir. 1985), *related compliance order,* 29 F.E.R.C. ¶ 61,225 (1984), *on reh'g,* 30 F.E.R.C. ¶ 61,012 (1985), *aff'd sub. nom. Ky. Utils. Co. v. FERC* 789 F.2d 1210 (6th Cir. 1986). In May 1978, KU notified Kentucky municipals[3] that it was terminating its existing requirements contracts with the municipals, and simultaneously proposed contracts for subsequent service that included a provision obliging each Kentucky municipal to purchase its full requirements from KU during the successor contract's term. The Commission found that the proposed eligibility restriction amounted to a "change in service" that raised the question, "has Kentucky justified the proposed change?"[4] Cognizant of its duty to avoid creating barriers to competition,[5] the Commission squarely rejected this proposed narrowing of KU's service offerings.

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[2] Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol, Order No. 436, 50 Fed. Reg. 42,408, corrected or amended 50 Fed. Reg. 45,907 (Oct. 18, 1985), [1982-1985 Regs. Preambles] F.E.R.C. Stat. & Regs. ¶ 30,665, at 31,530, *order on reh'g and clarification*, Order No. 436-A, 50 Fed. Reg. 52,217 (Dec. 23, 1985), 1982-1985 Regs. Preambles] F.E.R.C. Stat. & Regs. ¶ 30,675, *order on reh'g*, Order No. 436-B, 51 Fed. Reg. 6398 (Feb. 24, 1986), [1986-1990 Regs. Preambles] F.E.R.C. Stat. & Regs. ¶ 30,688, *reh'g denied*, Order No. 436-C, 34 F.E.R.C. ¶ 61,404, *reh'g denied*, Order No. 436-D, 34 F.E.R.C. ¶ 61,405, *reconsideration denied*, Order No. 436-E, 34 F.E.R.C. ¶ 61,403 (1986).

[3] The list of nine Kentucky municipals as it then stood is identified at *Kentucky Utils.,* 23 F.E.R.C. ¶ 61,317, p.61,686 n.1 (1983), and is similar to the group of twelve Kentucky Municipals intervening herein.

[4] *Id*. at 61,666.

[5] See Opinion No. 169 at 61,685 & n.113 ("we must be concerned that a term we approve might injure potential competition").

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KU tried to defend the proposed new eligibility restriction by making two principal arguments. First, KU asserted that the rate at which it was offering power to the municipals was designed for full requirements service and inappropriate for partial requirements service, and that KU should not have to design an alternative rate for the latter. But the Commission held that the same rate might well be appropriate, and that in any case the question whether an exercise of the option to dial back to partial requirements service should entail rate adjustments could and should be addressed after a municipal gave notice of its intention to do so:

> The appropriateness of a rate for a customer is not determined by labeling the customer as a full requirements customer or a partial requirements customer. Instead, the appropriateness of the rate is determined by looking at certain characteristics of the customer. If the characteristics of two customers are not significantly different, the customers should receive the same rate. The problem with the proposed availability clause is that *in some circumstances the characteristics of a customer that purchases less than its full requirements from Kentucky may not be significantly different from those of a customer that does*.

Opinion No. 169-A at 61,543 (emphasis added). Second, KU asserted that it could not plan for service to loads that might reduce their purchases. But the Commission held that while KU had a legitimate planning need for advance knowledge of whether requirements customers would be displacing KU power with their own generation, "this concern does not justify restricting the service offered to the customer's full requirements. Instead, it calls for the customer's giving adequate notice." Opinion No. 169 at 61,666-67. After extended litigation, the Commission determined what notice would be adequate: five years, reflecting the time needed to bring new generation on line, with the clock starting not when new generation is first imagined, but rather when major investment would be sunk in building out facilities planned for KU's forecast wholesale and retail loads. *See* Opinion No. 169 at 61,671 (notice period generally should be

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five years, to reflect "the period between the time the utility commits substantial amounts of capital to the construction of a generating unit and the time the unit is to go into service").

The Sixth Circuit affirmed, twice, the Commission's determination that KU must continue to make its requirements service available to Kentucky municipals who elect to use it to serve only part of their full requirements. *See* 766 F.2d at 249 (Commission directive that KU provide for "partial termination" of service quantities currently serving full load was "a legitimate pragmatic adjustment"); 789 F.2d at 1216 (affirming rejection of compliance language proposed by KU that would have "effectively prohibit[ed] customers from terminating part of their requirements").

History repeats itself, with KU's second attempt to eliminate the partial requirements option even more improper than the first. Here, KU recently committed, as part of the settlement agreement under which it was permitted to exit the Midwest ISO, that it would "not issue any termination notice under [the Existing Contracts] until January 1, 2011, and no such notice shall become effective prior to January 1, 2016."[6] Yet KU's present filing amounts to termination of the partial requirements service option that has, since the 1980s litigation, been available to Kentucky Municipals as a check on KU's business performance and rates. KU maintains that it should be allowed to terminate that option because (a) its retail rates are exceptionally low,[7]

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[6] The "Amended Agreement among Certain Intervenors and Applicants Regarding Applicants' Withdrawal from the Midwest ISO" ("KU-Municipals Exit Settlement") is on file with the Commission as Rate Schedule No. 402 of E.ON U.S. *See E.ON U.S., LLC*, Docket No. ER06-1279-000, Letter Order, Aug. 28, 2006 (accepting agreement subject to compliance filing); *E.ON U.S., LLC*, Docket No. ER06-1279-001, Letter Order, Nov. 9, 2006 (accepting compliance filing). The passage quoted in the text is from Section 3 of the KU-Municipals Exit Settlement, as quoted in the Transmittal Letter at 9 & n.26.

[7] *See* Transmittal Letter at 6 (citing relatively low average retail prices in Kentucky compared to national and neighboring-state benchmarks, and noting that KU's low prices contribute significantly to this average). Why the fact that KU has low retail prices should justify foreclosing wholesale options is not clear. If anything, the doctrine that the Commission should seek to promote competition would seem to dictate the opposite conclusion. See, e.g., *FPC v. Conway,* 426 U.S. 271 (1976); *Gulf States Utils. Co.* v. *FPC*, 411 U.S. 747 (1973).

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(b) its wholesale rates are low compared to those of other utilities nationwide,[8] and (c) "the Municipals have not taken actions towards, or voiced any interest in, requesting or seeking any specific alternative sources of electricity (other than SEPA), to replace requirements service supplied by KU."[9] But those arguments miss the point, and hardly rise to the level of a compelling public interest necessity or other basis to override KU's settlement commitment. If KU's rates remain attractively low, which is to be hoped but is by no means certain,[10] then Municipals will not exercise their partial requirements option. But the very existence of the option provides meaningful reassurance to Municipals, and to their residents and existing and prospective industrial customers, that if KU's rates were to rise, they would have the recourse of being able to transition towards greater self-sufficiency. It also serves as a check on KU's ability to flow through potentially imprudent costs, and thereby provides accountability that should improve KU's generation investment decisions. Especially in the context of formula rates that will flow increased costs through automatically, the customer safeguard and spur to efficiency provided by the partial requirements option should not be eliminated.

Contract aside, the 1980s precedent and its underlying bases continue to teach that eliminating the partial requirements option would not be just and reasonable. There has been no material change in circumstances that would warrant revisiting this settled precedent. First, KU's past argument that it had to foreclose partial requirements service lest it be called upon to

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[8] *See* Transmittal Letter at 6 (KU "has not conducted a survey," but "has reason to believe" that its wholesale rates are low, relative to others in the U.S.).

[9] *Id*.

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consider partial requirements pricing makes no more sense now than it did when the Commission and the courts rejected that argument in the 1980s. Indeed, today's facts render the argument even less credible now than it was then. The various Kentucky Municipals now come in three different power supply flavors. One, Berea, currently obtains all of its power from KU. Another, Paris, has substantial in-city generation that supplies most of its capacity needs. The others purchase SEPA power for part of their loads (as does Paris). Yet for all three potentially distinguishable groups of municipal customers, KU is proposing rates based on the same formula. Thus, it cannot be assumed that partial requirements rates would necessarily differ, per MW and MWh actually provided, from the rates that KU will charge to customers who have not exercised a partial requirements option.

If the lead time from breaking ground on new generation to commercial operation had materially changed since the 1980s, that might warrant shortening or lengthening the notice period, but even in that hypothetical case there would be no reason to narrow the availability as KU again proposes to do. In any event, the required lead time has not lengthened. Trimble Two, for example, is scheduled to enter commercial operation in June 2010, even though it was not even certificated until late 2005,[11] and the construction broke ground in August 2006.[12] Thus,

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[10] KU's rates are relatively low largely because KU has ample baseload coal resources, most of which is highly depreciated. Trimble Two will increase KU's fixed costs; but in a carbon-constrained future, and with the potential for a carbon tax, it and KU's existing resources may not be so cheap to run. Furthermore, a deep recession (as it the economy is widely believed to be entering) will decrease KU's loads and thereby increase its unit rates. Because KU has filed formula rates, this would not be the place to dispute the prudence of KU's power supply decisions, and Municipals are not doing so. Our point here is simply that KU's formula rate may not always result in an attractive price.

[11] See, for example, the Kentucky Public Service Commission's November 1, 2005 press release, announcing that the PSC "today approved the application of Louisville Gas & Electric Co. (LG&E) and Kentucky Utilities Co. (KU) to expand the Trimble County electric generating plant near Bedford." Available at http://migration.kentucky.gov/NR/exeres/4DB14281-C3A7-4FEA-B5F8-33F0E7DC2A33.htm.

[12] See E.ON's 2006 annual report to employees, available at http://www.eon-us.com/careers/emp_annual_report.pdf, at 8.

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judging by this major example, and others,[13] the lead time from major investment to operation is four years, which if anything would justify a shorter notice period.[14] *See generally New York v. FERC,* 535 U.S. 1, 4 n.4 (2002) (reciting finding in Order No. 888 at 31,641 that compared to the past, today's prototypical new generation plants are smaller and faster from conception to operation, typified by "smaller, 50-to-150 megawatt plants …with 1-year lead time").

Accordingly, the Commission should reach the same result here that it did when KU last sought to ensure that the Kentucky Municipals could begin swimming as generation direct owners only by plunging into the deep end of the pool. The proposed, narrowed eligibility restriction creates an unreasonable barrier to entry and should be rejected.

B. Withholding Capacity Credit for Future Purchases of SEPA Capacity Is Unreasonable

As what would become one of only two approved exceptions to full-requirements service (the other being Paris' use of its own generation) KU would allow Municipals to receive some, but not all, of the value of Southeastern Power Administration ("SEPA") federal power. Through January 21, 2011, KU would credit both the demand and energy provided by SEPA, thereby reducing the demand and energy deemed to be purchased from KU. But after that date, KU would recognize only the energy.[15]

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[13] Kentucky's second-largest ongoing generation construction project is East Kentucky Power Cooperative's Spurlock Unit No. 4. EKPC began construction in June 2006 and expects completion in April 2009, i.e., in less than three years. See EKPC's 2006 Annual Report, at 6 (available at http://www.ekpc.coop/publications/EKPC%20Annual%20Report%202006.pdf).

[14] Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, Order No. 888, 61 Fed. Reg. 21,539 (May 10, 1996), [1991–1996 Regs. Preambles] F.E.R.C. Stat. & Regs. ¶ 31,036, *clarified*, 76 F.E.R.C. ¶ 61,009 (1996), *modified*, Order No. 888-A, 62 Fed. Reg. 12,274 (Mar. 14, 1997), [1996–2000 Regs. Preambles] F.E.R.C. Stat. & Regs. ¶ 31,048, *order on reh'g*, Order No. 888-B, 62 Fed. Reg. 64,688 (Dec. 9, 1997), 81 F.E.R.C. ¶ 61,248 (1997), *order on reh'g*, Order No. 888-C, 82 F.E.R.C. ¶ 61,046 (1998), *aff'd in part and remanded in part sub nom. Transmission Access Policy Study Group v. FERC*, 225 F.3d 667 (D.C. Cir. 2000), *aff'd sub nom. New York v. FERC*, 535 U.S. 1 (2002).

[15] See Transmittal Letter at 8 and 15-16; ARA Section 3.6.4.

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SEPA power has both capacity and energy value. KU has not claimed, much less presented persuasive evidence, that the capacity value is immaterial. Both of these forms of value should flow through to the Municipals. It is not just and reasonable for KU to provide that it will seize the capacity value for itself, and KU has presented no reason why it should be allowed to do so.

If Municipals are placed in a situation where after 2010 they get no capacity value for SEPA power that they purchase, they may have no economic alternative but to forgo SEPA purchases and buy all of their power from KU. One can see why such monopolization might be to KU's advantage, but that does not make it just and reasonable. Furthermore, if the arrangements under which Municipals purchase SEPA power change such that a rate adjustment is warranted, KU can file accordingly at that time. But there is no need or basis to determine in the abstract, even before the post-2010 SEPA purchase terms are known, that Municipals will get no demand credit. The Commission should reject KU's proposals for the post-2010 treatment of SEPA capacity, just as, for multiple good reasons, it protected Municipals' rights to purchase and receive SEPA capacity in the 1980s litigation discussed in Part II.A above.

C. The ARA Section 3.1.4 Treatment of Post-Delivery Transmission Interests Violates Federal Power Act Section 217 and Raises an Unreasonable and Anticompetitive Barrier to Entry

KU's proposed ARA Section 3.1.4 attempts to require the Municipal buyers to abjure any "interest in any transmission service or transmission rights of any kind which Seller may possess or obtain in connection with the delivery of Requirements Electric Service or otherwise (including any transmission service used for the delivery of SEPA Power)." KU has submitted no testimonial or transmittal letter justification for this provision. To the extent this provision

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gives KU rather than Municipals the roll-over priority right to the transmission capacity currently used to serve Municipals, it is patently unstatutory and unreasonable, and should be rejected.

Under Order No. 888, wholesale requirements customers who purchase bundled power and transmission (*i.e.,* who purchase delivered power at their load centers) have a continuing option to become unbundled transmission customers and switch to purchasing power at the points where it is received onto the transmission system, and in doing so to apply a "right of first refusal" reservation priority to the transmission capability formerly used to deliver their requirements purchase:

> [A]ll firm transmission customers (requirements and transmission-only), upon the expiration of their contracts or at the time their contracts become subject to renewal or rollover, should have the right to continue to take transmission service from their existing transmission provider.
>
> ….
>
> ____
>
> [176] This right of first refusal exists whether or not the customer buys power from the historical utility supplier or another power supplier.

Order No. 888 at p.31,665 & n.176.

Federal Power Act Section 217, subsections (3)(A) and (4), codifies this first-refusal priority right:

> To the extent that all or a portion of the service obligation covered by … firm transmission rights or equivalent tradable or financial transmission rights is transferred to another load-serving entity, the successor load-serving entity shall be entitled to use the firm transmission rights or equivalent tradable or financial transmission rights associated with the transferred service obligation.

* * *

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> The Commission shall exercise the authority of the Commission under this chapter in a manner that … enables load-serving entities to secure firm transmission rights (or equivalent tradable or financial rights) on a long-term basis for long-term power supply arrangements made, or planned, to meet such needs.

Under these provisions, the firm transmission reservation priority of OATT Section 2.2 is meant to "follow the load" from supplier to supplier.[16] The underlying principle is that load-serving entities that use the transmission system, whether through unbundled transmission-only service or as part of a bundled arrangement, have a right of first refusal to continue using the same transmission capacity when their power supply arrangements change.

The Commission has had more occasions to apply this principle inside RTO areas than outside them. For example, FERC recently promulgated 18 C.F.R. § 42.1(d)(6), which provides that "A long-term transmission right held by a load serving entity to support a service obligation should be re-assignable to another entity that acquires that service obligation." FERC explained that this standard implements FPA Section 217. Long-Term Firm Transmission Rights in Organized Electricity Markets; Long-Term Transmission Rights in Markets Operated by Regional Transmission Organizations and Independent System Operators, 71 Fed. Reg. 6693, 6703 (proposed Feb. 9, 2006), [2004-2007 Proposed Regs.] F.E.R.C. Stat. & Regs. ¶ 32,598, PP 61-63 (to be codified at 18 C.F.R. pt. 40), *comment period extended*, 71 Fed. Reg. 11,557 (Mar. 6, 2006); Long-Term Firm Transmission Rights in Organized Electricity Markets, Order No. 681, 71 Fed. Reg. 43,564, 43,601-02 (Aug. 1, 2006), [2006-2007 Regs. Preambles] F.E.R.C. Stat. & Regs. ¶ 31,226, PP 356-360, *corrected*, 71 Fed. Reg. 46,078 (Aug. 11, 2006), *clarified*, Order No. 681-**A**, 71 Fed. Reg. 68,440 (Nov. 27, 2006), 117 F.E.R.C. ¶ 61,201 (2006).

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[16] In principle, congestion revenue rights should likewise follow the load, but because the KU/LG&E OATT does not currently utilize congestion pricing, the Commission need not address that issue now.

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However, the principle also applies in non-RTO transmission areas. *See, e.g., Tex.-N. M. Power Co. v. El Paso Elec. Co.,* 108 F.E.R.C. ¶ 63,045 (2004) (while finding that TNMP had not taken the actions necessary to preserve its rollover rights upon switching to a new supplier, indicating no doubt that formerly bundled wholesale requirements customers can claim a rollover priority upon switching suppliers).

None of this would be an issue if KU were proposing to fully unbundle transmission service, by selling requirements power to Municipals at the point where power is injected onto the KU/LG&E transmission system, for delivery under tariffed network transmission service purchased by Municipals as direct transmission customers. Under that structure, it would be obvious that Municipals are the transmission system user entitled under OATT Section 2.2 to the roll-over priority. However, in the present filing KU is proposing to give Municipals all the burdens of transmission customers (by flowing through all OATT transmission charges, except for those ancillary service charges that are duplicative of amounts flowed through the delivered power formula rate), while attempting to avoid flowing through to Municipals the roll-over priority benefit of being a transmission customer. That inconsistency is unreasonable.

In practice, splitting the transmission burdens and benefits as KU proposes would raise an anticompetitive barrier, further[17] burdening Municipals' ability to procure non-KU power if they would wish to do so after the initial service term ends. They would face a choice between continuing to purchase from KU or being treated as Johnnies-come-lately to the transmission system, at risk of having to wait for transmission expansion before they could take service and of having to pay incremental transmission prices. That playing field would not be level.

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[17] See also Part II.A (discussing how KU's proposal to eliminate the partial requirements option raises a barrier to entry).

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To prevent this unstatutory and unreasonable outcome, the Commission should make two things clear. First, that Municipals retain the option to convert to taking open access transmission service directly from KU's transmission function, rather than paying the transmission costs while leaving KU as the named customer. Second, that if and when Municipals do convert to direct purchasers of unbundled tariff transmission service, they rather than KU will retain the first-refusal right to use of the transmission capacity now being used to deliver their requirements purchase.

D. KU's Proposal to Flow CWIP through the Rate Formula Is Inconsistent with KU's Proposed Termination Right, Omits Information and Procedures Required by the CWIP Regulation, and Is Otherwise Unreasonable

KU proposes to include in its rate base more than half of its construction work in progress ("CWIP") balances, *i.e.,* 100% of its pollution control CWIP and 50% of its other CWIP. See Exhibit 4 at 18. These balances are very substantial, largely because KU is investing heavily in Trimble County Power Plant Unit No. 2 ("Trimble Two"). According to KU's filing at Exhibit 9, Schedule A-4, the CWIP balance that would flow into the rate formula as of 2007 (had the formula then been applicable) was $653,163,300 — approximately 2/3 as large as KU's entire net plant in service.

Simultaneously but inconsistently, KU proposes to retain the right to unilaterally terminate service on five years' notice.[18] Thus, KU is proposing to charge Kentucky Municipals for Trimble Two before it goes into service, including costs of facilities that will have an economic life measured in decades, while seeking to retain for itself the unilateral right to boot Kentucky Municipals off the system and thereafter keep for itself the output of the long-lived

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[18] See KU Exhibit 1, § 2.3.1. The five-year notice period is qualified, but only temporarily, by a provision under which termination "shall not become effective prior to January 1, 2016." *Id.*

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Trimble Two plant that they will have pre-funded. Combining in this fashion pre-funded rates with no long-term obligation to serve is unjust, unreasonable, unduly discriminatory, and anticompetitive.

Even if KU were entitled to charge CWIP while retaining a termination option, or deemed to be waiving that option by filing to collect for CWIP, its proposal to collect CWIP based on current (service year) usage ratios would remain patently inconsistent with Commission policy and regulations. Among other failings, KU has not "allocated [the test period CWIP project] to the customer classes *on the basis of forward looking allocation ratios reflecting the anticipated average annual use the wholesale customers will make of the system over the estimated service life of the project.*" 18 C.F.R. § 35.25(c)(4) (emphasis added).

Adjusting CWIP collection for forward-looking allocation ratios is no mere formality. It is essential to preventing CWIP collection from having anticompetitive effects, *i.e.,* from creating a "double whammy" under which wholesale customers currently purchasing all of their power requirements from the CWIP-spending utility could not develop their own generation without paying for both that generation and that of their supplier-competitor.

In *Mid-Tex Electric Coop., Inc. v. FERC,* 773 F.2d 327, 357-59 (D.C. Cir. 1985), the D.C. Circuit found that a "'double whammy' arises when a wholesale customer embarks on a construction program of its own in order to supply itself with all or part of its future power requirement," such that obliging it "to pay CWIP-based rates to its supplying utility" would oblige it to 'subsidize its competitor,' and pointed out that "FERC acknowledged that the 'double whammy' is inequitable and anticompetitive and that steps needed to be taken to minimize the possibility that the CWIP rule would have this effect." *Id.* at 357. In the rulemaking underlying 18 C.F.R. § 35.25, the requirement to use forward-looking allocation rations was, explicitly, the

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Commission's response to judicial criticism that "a wholesale customer may have a disincentive to build its own generation, because it would have to pay for its own construction program while contributing to its wholesale supplier's construction program." The Commission explained that the "CWIP-induced disincentive to build on the part of the wholesale customer is … mitigated by the reduction or elimination of its CWIP payments to its wholesale supplier based on the forward-looking allocation ratios" and that "[u]nder the final rule's mandatory use of forward looking allocation ratios, there is automatic accounting for the joint venture efforts, as well as any other alternative power supply efforts, of wholesale customers."[19]

Adhering to this competitively necessary requirement, the Commission has repeatedly, and correctly, rejected formula rates that allocate CWIP without accounting for anticipated usage over the CWIP project's service life, and therefore implicitly assume that usage ratios will remain constant from the time of CWIP collection through the years over which the CWIP-funded plant will be used to provide service. For example, in *Florida Power & Light Co.,* 59 F.E.R.C. ¶ 61,044 *reh'g granted on other grounds*, 59 F.E.R.C. ¶ 61,300 (1992), even in the absence of any relevant protest,[20] the Commission *sua sponte* rejected the CWIP component of a proposed formula rate for requirements service, on the ground that it lacked the "forward looking allocation ratios … required by [18 C.F.R.] section 35.26(c)(4)." *Id*. at 61,167. In so holding, the Commission rejected FPL's argument that forward-looking ratios "are not needed because

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[19] Electric Rates; Construction Work in Progress; Anticompetitive Implication, Order No. 474, 52 Fed. Reg. 23,948, 23,961-62 (June 26, 1987), [1986-1990 Regs. Preambles] F.E.R.C. Stat. & Regs. ¶ 30,751, at 3071, *order on reh'g and clarification,* Order No. 474-A, 52 Fed. Reg. 35,695 (Sept. 17, 1987), [1986-1990 Regs. Preambles] F.E.R.C. Stat. & Regs. ¶ 30,765, *remanded on other grounds, Mid-Tex Elec. Coop. v. FERC*, 864 F.2d 156 (D.C. Cir. 1988), *order on remand*, Order No. 474-B, 54 Fed. Reg. 32,802 (Aug. 10, 1989), [1986-1990 Regs. Preambles] F.E.R.C. Stat. & Regs. ¶ 30,858.

[20] The customer in that case, Florida Keys Electric Cooperative, endorsed the rate as filed. The only protest was filed by an unaffiliated cooperative (Seminole), which argued that the rate at issue was, on other grounds, unduly preferential.

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the formula does not include fixed allocation ratios and will respond automatically to changes in Florida Keys' demand." *Id*. The Commission explained that

> "Forward looking allocators are estimates of future demands which are used to allocate CWIP expenditures in currently proposed rates. Under this methodology, the customer's CWIP responsibility matches its ultimate cost responsibility when the facilities are placed in service. The Power Agreement formula's allocation of future costs using current allocation ratios does not ensure that Florida Keys' *current* CWIP responsibility will match its *future* power allocations and, hence, its cost responsibility. … Florida Keys' future demand responsibility could change even if it continues to purchase most of its requirements from Florida P&L (*e.g.*, if Florida P&L's load grows at a faster rate than Florida Keys')." Id.

Similarly, in *Wisconsin Public Service Corp.,* 103 F.E.R.C. ¶ 61,116, P 11 (2003), the Commission summarily rejected a requirements formula rate component that would have automatically flowed through CWIP, because the filing utility had not met the requirements of 18 C.F.R. § 35.25. *See also Am. Elec. Power Serv. Corp.,* 124 F.E.R.C. ¶ 61,306, P 27 (2008) ("Specifically with respect to CWIP that might be approved by the Commission, AEP will need to demonstrate in the relevant, future filing that it meets the applicable requirements."); *Sw. Elec. Power Co.,* 36 F.E.R.C. ¶ 61,081, at 61,202 (1986) (rejecting automatic formula flow-through of CWIP, and holding instead that "The annual update of OMPA's rate pursuant to the formula will require a filing with respect to the return on common equity and CWIP balances."); *Me. Yankee Atomic Power Co.,* 66 F.E.R.C. ¶ 61,375, *clarified*, 68 F.E.R.C. ¶ 61,190 (1994) (same). While the Commission has of late approved CWIP in certain <u>transmission</u> rates, in that context "double whammy" is not an issue, because wholesale customers who develop their own generation do not thereby leave the <u>transmission</u> system, making ongoing usage typically a good proxy for forward-looking allocation ratios. Not so as to requirements power rates, such as this one.

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Removing CWIP and replacing it with AFUDC would (as a single adjustment) reduce the test-period revenues by approximately $6,500,000.

E. KU's Proposal to Automatically Flow Pension and PBOP Costs Through as Booked Violates Commission Policy and Jeopardizes Intergenerational Equity

KU is proposing to automatically flow through both Pensions and Post-Employment Benefits Other than Pensions ("PBOPs"), by automatically picking up from each year's FERC Form 1 the entire amount booked to Account 926. See Exhibit 9, Schedule A-9, line 8 (showing approximately $22.25 million in "Employee Pensions & Benefits." Automatic flow-through is contrary to Commission policy, which requires a Section 205 filing before changing the PBOP amount flowed through a rate formula. *Commonwealth Edison Co.* 119 F.E.R.C. ¶ 61,238, P 91 (2007). The reason for this filing requirement is intergenerational equity: because the PBOPs booked in any given year reflect judgments about amortization, the Commission rightly insists on an opportunity to review whether those judgments are just and reasonable from a ratemaking standpoint. *See id.* That consideration is especially strong here, where pension and PBOP obligations booked now may serve to cover costs that were incurred or will be incurred at a time when the Municipals have more non-KU resources and therefore should be allocated a smaller share of KU's then-current system costs. Thus, the same intergenerational issues that are raised in Part II.D with regard to CWIP apply to pensions and PBOPs as well.

To illustrate the potential effect of this adjustment, removing half of the Account 926 costs from the formula inputs reduces the test-year revenue requirement by approximately $600,000.

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F. KU's Cost-of-Service Information Should Be Found Deficient, and KU's Request for Waiver of Cost of Service Filing Requirements Should Be Denied

The Commission's filing regulations establish a $200,000 ceiling for rate increases that can use abbreviated filing procedures over customer objection. 18 C.F.R. § 35.13(a)(2). By its own estimation (according to the incomplete past-period information that KU did include), KU is requesting a rate increase of approximately $ 4.8 million per year,[21] greatly exceeding that ceiling. Given the size of the proposed increase and the informational deficiencies discussed below, Kentucky Municipals object to the use of abbreviated filing procedures. Accordingly, KU should be required to provide full rate filing information, including the Period II information that is required by 18 C.F.R. § 35.13(d)(2).

In numerous material respects, KU's filing lacks information that is needed to check that the proposed formula is reasonable and will be applied[22] reasonably. Some examples, taking the Exhibit 9 "Schedules" *etc.* in sequence:

- Schedule A-1
  - KU filing does not include any supporting detail for CP demands used for allocation (Line 9) or NCP demands used as rate design denominator (Line 15).
  - References are made to "Note B" and "Note C," which are not provided anywhere on Schedule A-1.
  - AFUDC-related additions to revenue requirements at Lines 11-13 and other supporting workpapers will require discovery and additional analysis.

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[21] See Exhibit 12 (unnumbered page 2, last row of last column, showing a $4,799,744.61 rate increase if the present filing were applied to 2007).

[22] Some, but not all, of the deficiencies listed in the text go to the manner in which the formula template will be filled out each year, and therefore could in theory be cured at the annual updating stage. However, this data shows how KU intends to implement the formula, and therefore sheds light on the formula itself. Where a formula is open to a flawed interpretation and the filing utility has indicated it intends to apply that interpretation, the formula has perforce not been shown to be just and reasonable. Moreover, it would not be reasonable to put customers in the position of having to pay bills based on an unreasonable application of an ambiguous formula, whatever the potential may be for an eventual remedy. Accordingly, all of these deficiencies bear on the reasonableness of the proposed formula.

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- Schedule A-2
  - Schedule A-2 derives a per-MWh energy charge without first allocating energy-related costs to wholesale customers. This is in contrast to Schedule A-1, which derives the proposed demand charges by first allocating fixed costs to wholesale customers and then dividing by the sum of annual billing demands. Commission policy generally requires that the basis for allocating demand costs and the basis for allocating energy costs be consistent. *See, e.g., Ill. Power Co.,* 57 F.E.R.C. ¶ 61,213, at 61,699 (1991); *Fl. Power & Light Co.,* Order on Policy Issues, 66 F.E.R.C. ¶ 61,227 at 61,523 (1994), *on reh'g on other issues*, 70 F.E.R.C. ¶ 61,158 (1995), *rev'd in other part sub nom. Fla. Power & Light co. v. FERC*, 85 F.3d 684 (D.C. Cir. 1996). Additional analysis is required to ascertain whether the resulting energy charges produce the level of energy charges that would result if energy-related costs were allocated to the wholesale customers prior to computation of energy rates.
- Schedule A-3
  - Additional discovery and analysis are required to assess whether the amount of fuel expense shown at line 2 is overstated, resulting in understated margins on off-system sales.
- Schedule A-5 and Schedule A-5(a)
  - Column F of A-5 includes AFUDC-related amounts that KU subtracts from total company rate base then adds back to wholesale cost of service in Schedule A-1. Discovery will be required in order to track the historical AFUDC additions to rate base.
- Schedule A-8
  - The amount of Fuel expense at line 2, column E cannot be traced to KU's FERC Form 1. The referenced worksheet cell adds or subtracts additional values not found in KU's Form 1 or any other supporting documents.
- "Source Data Inputs" at the end of Exhibit 9
  - Elements of KU's addition of CWIP to rate base are presented as inputs to the cost of service model at lines 12 through 21. However, there is no support for the input values shown in column K ("2007") and no linkage is provided to the CWIP amounts reported in KU's 2007 FERC Form 1. In particular at line 16 and 17, KU makes reference to "ECR Filing" and "2007 ECR Workpapers" that are not provided with the filing. Those supporting documents and discovery will be required to assess the appropriateness of the KU's proposed additions of CWIP to rate base.
  - A&G expense input values for the cost of service model are presented at lines 186 through 198. Potential issues/questions include whether Outside Services at line 189 should be functionalized before allocation. Discovery will be required to determine whether elements of Industry Association Dues are not properly allocable to wholesale customers. This is also true for research expenses at line 197.
  - ARO Accumulated Depreciation, Lines 264-269 – these input values cannot be found in KU's Ferc Form 1, and no other documentation is provided to support the input values used.

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KU seeks to paper over these deficiencies by requesting a discretionary waiver of the Commission's cost-of-service filing requirements. It has filed a truncated "rate comparison" for 2007, but asserts that Period II information is unnecessary because KU is proposing formula rates.[23] However, the Commission has not issued a blanket waiver of its filing regulations such that formula rate filings can omit Period II data. Rather, it has insisted on Period II information where that information will shed light on whether the proposed formula is just and reasonable. *See South. Co. Servs., Inc.* 99 F.E.R.C. ¶ 61,069 (2002) (requiring projections of formula rate billing determinants and revenues, both upon initial filing and to accompany annual updates, while permitting aggregate revenue projections as among short-term transactions); *Fla. Power & Light Co.,* 67 F.E.R.C. at 62,147 (requiring filing of Period I and II data in a proceeding where the filing utility proposed to adopt formula rates).

Here, proposed changes to terms, conditions, and rate design make apples-to-apples rate comparisons and Period II information essential, notwithstanding the formulaic nature of the proposed rates. For example, KU is proposing formulaic recovery of CWIP, but has not provided Period II information on the CWIP at issue or on how it would flow through. Furthermore, while KU provides (in Exhibit 12) a summary comparison between 2007 rates as billed and the amounts that would have been billed for that past year had the proposed rates been in effect then, it provides no quantification indicating what prospective effect the proposed rate change actually will have if allowed to go into effect.

The three cases that KU (Transmittal Letter at 22 n.44) cites in support of waiving the required information are not persuasive. In *Xcel Energy Services, Inc.*, 122 F.E.R.C. ¶ 61,098 (2008), the filing utility provided considerably more information than KU has presented here,

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[23] See Transmittal Letter at 22 & n.44.

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including "seven sets of testimony," *id*. P 76. In *Idaho Power Co.*, 115 F.E.R.C. ¶ 61,281, P 20 (2006), the filing utility provided "all of the Period I statements," along with "Statements BG, BH and BL" for Period II — far more than KU has provided here. In *Allegheny Power System Operating Cos.*, 111 F.E.R.C. ¶ 61,308, P 56 (2005), the filing at issue resulted in a rate decrease, and the Commission expressly provided for discovery of all relevant cost-of-service information. And in all of these cases, the rate increase was limited to transmission, and thus had a more attenuated effect on unaffiliated wholesale customers than the present delivered-power rate increase.

Accordingly, the Commission should issue a deficiency letter and instruct KU to provide substantially more information so as to enable meaningful evaluation of how its proposed formulas will be applied in practice and of how they will affect Municipals' rates.

G. The Proposal to Base the Demand Charge on Year-End Rather than 13-Monthly or Year-Beginning/Year-End Average Balances Is Contrary to Commission Policy and Unreasonable

Under the proposed formula rate, the $/MW capacity unit rate to be made effective each July 1 would reflect the prior calendar year's year-end balances, paired with that year's 12-month loads. In other words, the rate update to take effect July 1, 2009 will take as its numerator costs based on a December 31, 2008 snapshot, including Construction Work In Progress; these year-end costs will then be divided by loads experienced over the twelve months of 2008; and the resulting unit rate will be applied to KW and KWh purchased during 2009.

This rate design will systematically over-recover KU's costs, and is therefore unjust and unreasonable. It inappropriately uses year-end ("YE") balances rather than either 13-monthly average balances or the average of year-beginning and year-end ("YB/YE") balances. Commission policy requires year-average rate base. For example, in *American Electric Power*

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Service Corp., 121 F.E.R.C. ¶ 61,245, P 12 (2007), the Commission granted rehearing of an order that had set the issue for hearing, and instead summarily rejected AEP's proposal to use year-end balances. The Commission summarily directed AEP "to include in its case-in-chief at the hearing a formula rate template that reflects the average of thirteen monthly plant balances." *Id*. And this was hardly the first time the Commission rejected reliance on a year-end rate base. Since the 1970s, the "issue of average versus year end rate base" has been "well settled." That is, "[t]he Commission has consistently required the use of an average rather than year end rate base."[24]

The reason for requiring year-average rather than year-end rate base is straightforward: costs and loads must be properly matched in developing and applying unit rates. Proper matching is essential where, as here, the cost per unit of service would be determined based on data from one period and applied to the units of service sold during a later period. Given such a lag, as the Commission explained in rejecting the year-end method more than a half-century ago, a utility that "anticipates a steady growth in its sales volumes" will over-recover, unless the rate numerator reflects the <u>average</u> investment during the same period that underlies the rate divisor.[25] That is, in this context the rate base must be "a reasonable approximation of the average continuous plant balance," rather than one "computed as of one ['end of the test period'] point in time."

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[24] *Lockhart Power Co.,* 4 F.E.R.C. ¶ 61,337 (1978). *See also, e.g., Florida Power & Light Co.,* 56 F.P.C. 3581, 3633 (1974) ("The contentions of the Company to the contrary notwithstanding, the important principle enunciated by the Commission which requires sales volumes, revenues and expenses to be adjusted whenever the use of a year-end rate base is sought cannot be ignored. FP&L has made no such adjustments and it has not shown by any detailed evidence, as contrasted with bare allegations, why and how that principle of synchronization is not applicable here."); *Nevada Power Co.,* 56 F.P.C. 84, 86 (1976). *Cf. New England Power Co.,* 9 F.E.R.C. ¶ 63,056 (1979) ("The average plant balance for a test-year should reflect the balance at the beginning and end of the year and all months in between. In this way, rate base is properly matched with revenues received and expenses incurred between the first and last day of the test year."); *Public Serv. Co. of Ind.* 56 F.P.C. 3003, 3025 (1976).

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Matching is necessary because "the size of the plant investment in a particular period is related to sales of such period."[26] This proportional relationship of costs to loads is the very premise of KU's proposal to use a lagging formula, in which unit rates developed from the 2008 Form 1 will be applied to 2009 loads.[27] With such a lag, the escalation in loads from (*e.g.*) 2008 to 2009 must be counter-balanced by a rate numerator that, just like the rate divisor, lags by one year. If rate base is a single year-end snapshot whereas loads are taken from throughout the test period, the unit rate will exceed the prior year's per-unit costs, and therefore will be expected to return excessive revenues. Consider also that year-end rate base includes plant that enters service late in the year (*e.g.,* in fall, after the summer construction season ends) in order to be available to meet the next summer's peak load. For synchronism with a rate divisor that reflects average 12 CP load during the full prior year, the costs that flow into the rate numerator should reflect the average costs during that same full prior year.[28]

This general principle requiring use of an average rate base to avoid over-recovery is fully applicable to KU. KU forecasts continuing load growth during the years when its proposed formula rate would be charged. In the KU/LG&E Integrated Resource Plan currently pending at

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[25] *United Fuel Gas Co.,* 12 F.P.C. 251, 255-56 (1953).

[26] *Id*. at 256.

[27] Such a rate design will necessarily recover in 2009 more than 2008 costs, but that is not inherently reasonable, because the design implicit assumes that load growth from 2008 to 2009 will be paralleled by cost growth from 2008 to 2009, such that per unit costs will hold steady.

[28] *See FPL,* 56 F.P.C. 3581, at 3599:

> The Commission's long-standing policy in determining rate base has been to use the average rate base, although the Commission has indicated that it might consider the year end balance in a proper case. *United Fuel Gas Company,* 12 FPC 251, 255 (1949); *Otter Tail Power Company,* 8 FPC 393, 400-401 (1953). When using year end rate base, however, the Commission has advised that it is necessary to adjust the cost of service, sales and revenues to reflect conditions on the system that will exist in the immediate future with the full utilization of the new facilities, in order to avoid the distorting impact of a large block of generating capacity. *Appalachian Power Company,* Docket No. E-7775 (order issued June 9, 1975, 53 FPC 1956 at 1961). In each case the objective is to preserve the matching concept.

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the KYPSC), system loads are forecast to rise at approximately 1.5% per year through 2012 and then 1.0% per year through 2017, averaging to about 1.3% per year.[29] In anticipation of that growth, KU is investing heavily in Construction Work In Progress, highlighted by the very substantial funds that it continues to pour into building Trimble County Power Plant Unit No. 2 ("Trimble Two"). KU's year-end rate base is therefore likely to be significantly larger than its year-average rate base, and next-year load is likely to be significantly larger than its prior-year load. That is why it is seeking CWIP (as discussed in Part II.D below) and presumably is why it is seeking formula rates. Consequently, KU's YE rate base can be expected to generally exceed YB/YE rate base.

KU Witness Seelye (Exhibit 4 at 17) asserts that it is common for lagging-type formula rates to use a year-end rate base in order to reduce "the lag between cost determination and cost recovery …. both for the Company and the customer," but he misses a crucial distinction. Reducing the revenue requirement (*i.e.,* rate numerator) lag without also reducing the load input to the unit rate (*i.e.,* the rate divisor) will reduce the lag for the Company's benefit, but not commensurately reduce the lag for customers' benefits. The end result would be unreasonable.

The particular form of year-average balance (*i.e.,* 13 monthly balances *vs*. the simple average of year-beginning and year-end balances), while material, is less important than the principle that year-average rather than year-end balances must be used. On this secondary point, Commission policy generally requires 13-month balances, *see San Diego Gas & Elec. Co*., 118 F.E.R.C. ¶ 61,073, P 29 (granting summary disposition and directing SDG&E to modify its formula transmission rate to use 13-month average plant balances), while leaving the door open

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[29] See Table 5.(3)-2 in the KU/LG&E Joint Integrated Resource Plan, filed April 21, 2008 in KY PSC Case No. 2008-00148. The relevant excerpt is Attachment 2 hereto.

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to the possibility that in a settlement context, customers may prefer to simplify formula rate administration and monitoring by substituting YB/YE balances, *see Am. Elec. Power Serv. Corp.*, 121 F.E.R.C. ¶ 61,245, P 12 (2007). In a settlement context, Kentucky Municipals would be willing to explore a formula that used YB/YE balances on most accounts, although they would favor the use of 13-monthly balances for accounts that have a major rate impact and for which the difference between YB/YE and 13-monthly balances is likely to be material.[30]

The effect of moving to 13-monthly balances cannot yet be quantified, because KU has not provided the necessary monthly data. However, it is indicated by the effect of adjusting the rate base to the YB/YE average. That effect is approximately $670,000, when calculated after removing CWIP and reducing pensions and benefits for the reasons discussed in Parts II.D-II.E above, such that this adjustment is in addition to the adjustments quantified above. On a stand-alone basis, it would be even larger.

H. The Proposed Return on Equity Is Excessive and Not Adequately Supported

KU seeks an 11.8% Return on Equity ("ROE"), and submits in support, as "Exhibit 5" with its supporting exhibits "KU-_1" through "KU-_6" [sic[31]], the ROE analysis of Dr. William Avera. That analysis does not, however, follow the Commission's policies. Municipals have identified several errors in Dr. Avera's analysis: Dr. Avera does not follow the Commission's policies for screening the proxy group. Dr. Avera has not followed the Commission's policy of

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[30] For example, if CWIP is allowed, it will have a major rate impact, and given the uneven distribution of construction activities over the course of a calendar year, is likely to have a 13-monthly average balance substantially different from its YB/YE balance. Accordingly, this is a rate impact for which the administrative costs of 13-monthly average balances are likely to be worthwhile.

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using the median to develop the ROE for a single company. Dr. Avera provides a Capital Asset Pricing Model ("CAPM") analysis that the Commission has explicitly rejected. Once Dr. Avera's errors are corrected, the median ROE of the better-screened proxy group is 9.7%.

At this stage of the proceeding, there is limited information available in the filing on the ROE and overall cost of capital issues, no opportunity to conduct discovery, and little time for in-depth or independent analyses. During the hearing procedures that should be established, other ROE and capital structure issues may come to light that would impact the allowable overall cost of capital and rates. Therefore, the broader issues impacting the overall cost of capital and allowable rate of return on rate base should be set for hearing in addition to just the level of the appropriate ROE to be used in the rates. If the Commission chooses to decide ROE at this time, however, the ROE should be no higher than the 9.7% median of Dr. Avera's proxy group after more appropriate screening for risk comparability. For purposes of the *West Texas* test for full suspension, that is the ROE that should be used; but for the sake of conservatism, and to avoid needless controversy given that the *West Texas* test is met by a wide margin, Municipals' quantifications of their rate adjustments use a preliminary ROE that is 50 basis points higher, at 10.2%. After the adjustments previously discussed, the incremental effect of reducing the ROE to 10.2% is a reduction in the annual cost of service of approximately $1.2 million.

1. KU's proxy group has not been properly screened

KU witness Avera has developed a 26-company "Electric Utility Proxy Group" selected for two characteristics and three qualities. The required characteristics were that to be a

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[31] Dr. Avera's exhibit nomenclature is potentially confusing, because it numbers exhibits to his testimony, which itself comprises Exhibit 5 of the filing. For clarity, we refer to the filing's primary, tabbed exhibits as "Exhibit 1" through Exhibit 24," of which Dr. Avera's testimony comprises Exhibit 5, and in turn contains "Exh. KU-_1" through "Exh. KU-_6." Note also that in at least some copies furnished by KU, Dr. Avera's testimony and exhibits are included twice.

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candidate, the firm must be listed in Value Line's "Electric Utilities Industry" group and must be covered by both Value Line and IBES. These screens implicitly require that each proxy be publicly traded, which in turn typically means that it is a holding-company level entity rather than an operating utility. The three qualities were (1) S&P corporate credit ratings between BBB and A-, (2) a Value Line "Safety Rank" of 2 or 3, and (3) a Value Line "Financial Strength" rating between B+ and A.[32] Dr. Avera opines,[33] but nowhere substantiates, that the resulting 26 proxies form a group comparable to KU.

Because Value Line does not publish reports on KU (KU being wholly owned by E.ON), there is no easy way to evaluate whether qualities 2 and 3 (namely, Value Line's Safety Rank and Financial Strength ratings) screen for companies comparable to KU. Only for quality 1, the corporate credit rating, is there a meaningful KU benchmark. And on that score, the S&P corporate credit rating indicates that KU is materially less risky than the proxy group average. Dr. Avera states that "KU is rated 'BBB+' by S&P, which is identical to the average rating for the utilities in the Electric Utility Proxy Group, as shown on Exh[.] KU-_2."[34] But that statement is misleading. Reference to Exh. KU-_2 shows that for the 26 members[35] of the Electric Utility Proxy Group, the number of proxies that were rated A-, BBB+, and BBB, respectively, were as follows:

Rating	Proxies So Rated
A-	5

[32] See KU Exhibit 5 at 24.

[33] *See id.* at 24-25.

[34] *Id*. at 25.

[35] The referenced exhibit also includes data for Constellation Energy, which is shown with an S&P Credit Rating of BBB+ and apparently included in the average shown on that page. Because Dr. Avera excluded Constellation from his 26-member proxy group (on other grounds), it is omitted from the discussion in the text.

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BBB+	9
BBB	12

Given this distribution, it is misleading to say that the average was "BBB+." If one calculates a numerical average by assigning the number 1 to an A- rating, 2 to BBB+, and 3 to BBB, the average (mean) among the 26 proxies' ratings is not 2 but rather 2.27, *i.e.,* is markedly closer to BBB than to A-. So far as this risk indicator goes — and it is the only one for which Dr. Avera's study provides any data to go on — it indicates that the proxy group is on average materially less risky than KU, which has an S&P corporate credit rating of BBB+.

Even more significantly, the Moody's issuer rating for KU is A2, which is the equivalent of an S&P rating of A. Thus, according to this indicator, KU is less risky than <u>any</u> of the 26 utilities in Dr. Avera's proposed proxy group. As shown on Attachment 3 hereto, for the 26 members of the Electric Utility Proxy Group, the number of proxies that are rated in each Moody's category are as follows:

Rating	Proxies So Rated
A3	5
Baa1	6
Baa2	10
Baa3	3

<u>None</u> of the proxies have a Moody's rating as good as KU's A2, further confirming that KU is considered to be significantly less risky than the proxy group chosen by Dr. Avera.

Note also that KU has a materially more equity-heavy capital structure (53.18% common equity, 46.82% long-term debt)[36] than does his proposed proxy group, for which long-term debt

[36] See KU Exhibit 5 at 60.

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is larger on average than common equity.[37] All else being equal, equity invested in a firm with more equity in its capital structure is safer than equity invested in a firm with more debt: in the former case, a given quantity of business risk has to be covered for more bondholders, and gets spread more broadly among equity holders. Accordingly, on all three metrics, equity capital invested in KU is significantly less at risk than equity capital invested in the 26 firms in Dr. Avera's proposed proxy group.

In addition to incorrectly screening his proxy group based on risk, Dr. Avera has insufficiently screened out utilities with unsustainable growth rates. While Dr. Avera does screen out Cleco Corp., Integrys, and PPL Corp. as "clearly extreme outliers,"[38] he does not screen out DPL, Entergy, or PSE&G. The IBES growth rates for these firms are 11.2%, 12.4%, and 11.9%, respectively. No reasonable investor should anticipate that these extreme ROEs are sustainable over the long term.

In performing his screen for unsustainable growth rates in evaluating his proposed proxy group, Dr. Avera did not apply the screen correctly in accordance with Commission policy. Dr. Avera eliminates the "high" implied cost of equity for Cleco Corp., Integrys, and PPL Corp, but fails to eliminate the "low" value for those companies. The Commission made clear in *Potomac-Appalachian Transmission Highline, L.L.C.,* 122 F.E.R.C. ¶ 61,188 ("*PATH*") that if either the low or the high implied cost of equity is eliminated, both must be eliminated.[39] Dr. Avera

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[37] See KU-_6, showing the average capital structure for a group of 27 utilities consisting of the proposed 26 proxies plus Constellation. Constellation should be removed from this average, but the only effect of doing so would be to slightly increase the debt share of the average capital structure.

[38] KU Exhibit 5 at 40.

[39] *PATH* at 101. Dr. Avera also eliminates the low ICOEs for DTE Energy, Duke Energy, Great Plains Energy, Hawaiian Energy, IDACORP, Otter Tail, and Progress Energy, but not the corresponding high value. That is an error to the extent these low values were correctly eliminated.

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disagrees with that precedent,[40] but fails (among other shortcomings) to recognize that because investors are influenced by both IBES and Value Line projections, and those projections in turn influence study period and forecast share prices and thus ICOEs, an unsustainable short-term growth rate forecast by either publisher will affect both the high and the low ICOE for that company.

Another screening error committed by Dr. Avera is his exclusion of DTE Energy, Duke Energy, Great Plains Energy, Hawaiian Energy, IDACORP, Otter Tail, and Progress Energy, on the ground that they have low-side Implied Costs of Equity ranging from 7.1% to 7.9%, which he deems unacceptably close to his study-period BBB bond yield of 6.7%.[41] But the Commission has made clear that low-end results should be retained if they "are above the cost of debt,"[42] and does not require that they exceed the debt cost by the 120-basis-point margin that Dr. Avera seeks to require. On that basis, the Commission recently retained a 6.7% Implied Cost of Equity that Dr. Avera thought should be excluded, on the ground that it exceeded that proxies' debt cost by only 30 basis points.[43] All of the ICOEs that Dr. Avera seeks to exclude as "too low" exceed the study-period cost of debt by at least 40 basis points, and some exceed it by as much as 120 basis points. None of them should be eliminated on that basis, both under Commission precedent[44] and as a matter of logic.[45]

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[40] *See* KU Exhibit 5 at 41-43.

[41] KU Exhibit 5 at 38.

[42] *PATH* P 102.

[43] *See id.* and Exhibit PTH-400 in *PATH* at 42 (showing a 30 basis points differential between the UIL low implied cost of equity of 6.7% and the 6.4% six month average Moody's Baa bond yield).

[44] See *PATH* P 101 and the cases cited therein.

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Furthermore, Dr. Avera uses the wrong debt cost benchmark. Because the Moody's Issuer Rating for KU is A2, the appropriate Moody's index would be Moody's A Rated Public Utility Index, not the Baa index used by Dr. Avera. The average Moody's A Rated Public Utility Index yield for the six months ending June 2008 is 6.2%, 50 basis points less than the 6.7% average for the Baa index erroneously used by Dr. Avera. Therefore, all of the ICOEs that Dr. Avera excluded are actually at least 90 basis points above the more appropriate debt cost benchmark yield, and some exceed it by as much as 170 basis points. Dr. Avera's exclusion of those results erroneously inflate his recommended ROE, and such exclusion must be corrected.

2. KU's study fails to follow Commission policy that uses the median to determine the appropriate ROE for a single utility

In its two most recent opinions that have decided the appropriate ROE for a single electric utility, the Commission has explicitly stated that the median should be used to calculate the ROE.[46] The Commission's reliance on the median in these two cases is not new. The Commission has recognized that the best measure of central tendency of a group of calculated ROE results is the median, and that the median should be used where the ROE is being determined for a single utility with risks approximately the same as the average for the proxy group.[47] Here, the Commission is tasked with determining the appropriate ROE for a single company, KU. While (as discussed above) KU is less risky than the average for the proxy group,

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[45] Under a methodology that computes both a low and a high ICOE for each proxy, it is not logically necessary that the lower ICOE significantly exceed the cost of debt. The argument for excluding low-end ICOEs is that investors would not logically invest in equities at a return that does not exceed the return on debt, which is less risky. But where two ICOEs are being calculated for each proxy and ICOEs that do not at least equal the debt cost are excluded, the question is whether an investor would spurn an equity investment for which the return might equal debt (at the lower ICOE), but also might exceed it (at the higher ICOE). It is not illogical to place such a bet.

[46] *Va. Elec. & Power Co.*, 123 F.E.R.C. ¶ 61,098, P 67 & n.58 (2008); *Golden Spread Elec. Coop., Inc. v. Sw. Pub. Serv. Co.*, Opinion No. 501, 123 F.E.R.C. ¶ 61,047, PP 62-64 (2008).

[47] Opinion 501 at P 63.

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such that an ROE below the median might be considered, there is no basis here to look to the midpoint or to an ROE above the median.

Dr. Avera asserts that the Commission's recent decisions in *VEPCO* and *Golden Spread* are not a "reasoned basis" for looking to the median.[48] But it is his criticisms of the Commission's reasons for looking to the median that lack sense.

First, he argues that the Commission's use of the median is a new development.[49] Not so. In *Northwest Pipeline Corporation*, the Commission determined that the median best represents the central tendency in a skewed distribution and is therefore preferable to the midpoint.[50] The Commission there explained that, since the midpoint is the average of the highest and lowest numbers in the group, it is clearly subject to distortion by extremely high or low values. The Commission also explained that "[t]hese statistical facts make the median an appropriate average to use to represent the typical observation in a skewed distribution because it is less affected by extreme numbers than the mean."[51] The Commission supported its rationale for using the median through statistics texts and concepts that are applicable generically to any numerical distribution, not merely to a pipeline DCF-calculated ROE distribution.

In arguing for the use of a midpoint, Dr. Avera cites cases such as the Commission's decisions setting an ROE for the entire Midwest ISO. While the Commission has relied on the midpoint for determining the ROE for an RTO, the Commission has clearly explained why setting the ROE for a single company, such as KU, is different and why, when setting the ROE

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[48] KU Exhibit 5 at 45, lines 1-5.

[49] See KU Exhibit 5 at 43-44.

[50] 99 F.E.R.C. ¶ 61,305 at 62,276 (2002) ("*Northwest Pipeline*").

[51] *Id*. (footnote omitted).

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for a single company, it is appropriate to use the median. At paragraphs 63 and 64 of Opinion 501, the Commission stated:

> 63. When deriving the ROE for an individual utility facing average risk, the Commission has held that the median best represents the central tendency in a proxy group with a skewed distribution of returns.[127] In *Midwest ISO*[128] the Commission contrasted the formula for deriving the ROE for an individual utility versus the formula for deriving the ROE for a diverse group of utilities included in the Midwest ISO.
>
> Because the ROE in this case will apply to a diverse group of companies, the entire range of results yielded by the subset is relevant here. Thus, we find that using the midpoint is the most appropriate measure for determining a single ROE for all Midwest ISO [transmission operators], since it fully considers that range. Selecting the most refined measure of central tendency, as might be achieved with use of the median, is not the Commission's goal in this case, given that we are not selecting a ROE for a single utility of average risk.[129]
>
> 64. Here, we are determining the just and reasonable ROE for a single utility of average risk and find the median to be appropriate for setting the ROE. In *Transcontinental Gas Pipe Line Corp.*,[130] the Commission determined that setting the ROE at the median of the zone of reasonableness lessens the impact of any single proxy company whose ROE is atypically high or low.

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[127] *Northwest Pipeline Corp.*, 99 FERC ¶ 61,305, at 62,276 (2002). However, as discussed further below, to the extent that the Commission determines that an applicant is not of average risk vis-à-vis the proxy group, then the Commission's *Southern California Edison* precedent would apply to the determination of the appropriate ROE within the range of reasonableness.

[128] 106 FERC ¶ 61,302 at P 10.

[129] *Midwest ISO*, 106 FERC ¶ 61,302, at P 10.

[130] 84 FERC ¶ 61,084, *aff'd Opinion No. 414-B*, 85 FERC ¶ 61,323 (1998).

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The Commission has confirmed its *Golden Spread* analysis in its *VEPCO* decision. The Commission stated that "the Commission's precedent on ROE for individual companies requires the use of the median of the calculated ROE of companies in the proxy group, rather than the midpoint used by VEPCO."[52] The Commission went on to explain:

> In the instant proceeding, we are determining the appropriate ROE for an individual utility of average risk, rather than a group of utilities. We agree with Indicated Customers that, in this circumstance, use of the median rather than the midpoint is appropriate because the median 'best represents the central tendency in a proxy group with a skewed distribution of returns.' As we found in Opinion No. 501, 'using the median also has the advantage of taking into account more of the companies in a proxy group rather than only those at the top and bottom.'[53]

Obviously, since the Commission's careful re-evaluation of the appropriate use of the midpoint, median and mean in determining the allowable ROE for electric utilities in *Midwest ISO*, 106 F.E.R.C. ¶ 61,302 (2004), the Commission has made clear that its prior practice of using the midpoint for electric utilities other than in the unique circumstances where a single ROE is being determined for across-the-board application to several different utilities is not appropriate and that the median, which is the better measure of central tendency, will be used where the cost of common equity capital is being determined for a single utility.

Second, he asserts that the Commission's practice of eliminating ICOEs deemed to be high or low outliers makes it reasonable to locate the cost of equity at the midpoint of the two companies that are the most extreme without being quite extreme enough to be eliminated.[54] But whether an ICOE is sufficiently credible to be retained is a judgment call, not an objectively obvious binary quality. Short of eliminating all companies with growth rates that exceed the

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[52] *VEPCO* P 58.

[53] *Id.* P 66 (footnotes omitted).

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long-term global growth rate, whether a growth rate is too high to be sustainable in the medium term will be inherently debatable. Even at the low end, where the line might be brighter, Dr. Avera has sometimes maintained that 100 basis points above the cost of debt is as sufficient spread to warrant retaining a low ICOE;[55] but here maintains that a 120 basis point spread is necessary;[56] yet ought to concede that the Commission has found that at a spread of zero-to-40-basis points is sufficient.[57] Accordingly, a methodology that relied on the midpoint would devolve into an unedifying, but pivotal, debate over which candidate proxies are just reasonable enough to be retained.

Third, he argues that the median "considers less information about the distribution of reasonable DCF results for the proxy group than does the midpoint," because the median of a distribution with an even number[58] of results is the average of only two numbers, those falling in the middle of the distribution.[59] That supposed mark against the median measure makes no sense. The midpoint is likewise the average of two numbers, those falling at the ends of the distribution. If the number of inputs at the very last step somehow mattered, the fact is that for both measures the last calculation step involves averaging two numbers. The meaningful point is that the extremes are the more distortion-risking two numbers to consider at that last step.

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[54] *Id.* at 45.

[55] *See Bangor Hydro-Electric Co.,* 111 F.E.R.C. ¶ 63,048 P 17 (2005), *aff'd,* Opinion No. 489, 117 F.E.R.C. ¶ 61,129 (2006), *on reh'g,* 122 F.E.R.C. ¶ 61,265 (2008).

[56] KU Exhibit 5 at 38.

[57] *PATH,* 122 F.E.R.C. ¶ 61,188 P 102.

[58] Dr. Avera also discusses distributions containing an odd number of results, but fails to recognize that a methodology that identifies two ICOEs per retained company necessarily yields a distribution containing an even number of results. In any case, the fallacy of asserting that the median contains less information than the midpoint is as fallacious for odd-numbered sets as it is for even-numbered sets. In both cases, the median is located by reference to every result in the distribution.

[59] KU Exhibit 5 at 45, lines 21-22.

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Fourth, he argues that the midpoint of the extremes doesn't completely disregard the middle numbers, because the extremes achieve their status as extremes by reference to the entire distribution.[60] That is no reason to prefer the midpoint to the median; it is equally true that the middle number(s) that identify the median achieve their status as middle number(s) by reference to the entire distribution. Where the two measures do differ is that only the midpoint amplifies the effect of variations at the extremes — it is more vulnerable than the median to being distorted by fluctuations in share prices and other inputs that move the extremes disproportionately up or down, and more vulnerable to the consequences of potentially erroneous decisions to retain or exclude results at the high and low margins. Simply put, the median is the more robust, stable, and reliable measure — as the Commission held in *Northwest Pipeline Corp* when it responded on remand to precisely this point.

3. Adjusting KU's study to focus on BBB+ companies yields a median of 9.7%

For the reasons discussed in Part II.H.1 above, if the Commission elects to start with Dr. Avera's proposed proxy group (rather than, for example, applying a geographically-screened proxy group), it should narrow that group so as to eliminate its bias towards relatively risky companies. A conservative way to do that, while still retaining an ample number of proxies,[61] would be to focus only on the firms among Dr. Avera's 26 proxies that have an S&P corporate credit rating of BBB+, the same as KU. As shown on Exh. KU-_2, there are nine such firms:

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[60] *Id*. at 46.

[61] In *PATH*, where the Commission started with a group of candidate proxies that was limited by a geographic screen, it accepted a proxy group that included firms rated one notch higher and one notch lower than the company whose ROE was at issue, looking to both Moody's and S&P ratings for this purpose. 122 F.E.R.C. ¶ 61,188 P 98. Where a geographic screen has already been imposed, broadening the credit rating screen may be necessary in order to ensure that the distribution contains enough results to be reliable. Because Dr. Avera has not imposed a geographic screen (he includes, for example, Hawaiian Electric and Portland General Electric), in this case the corporate credit rating screen can be applied with a tighter focus.

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Allete, Alliant, Otter Tail, PG&E, Portland General Electric, Progress Energy, Sempra Energy, Wisconsin Energy, and Xcel Energy. The median ICOE for those nine proxies is 9.7%. That result holds either if all 9 of those proxies, with their 18 results, are retained, or if the proxies that have results deemed illogically high or low by Dr. Avera are eliminated.

4. KU's "Capital Asset Pricing Model" and assertions regarding flotation costs should be disregarded

The Commission has long followed a policy of relying on DCF analysis to set electric ROEs.[62] Nonetheless, Dr. Avera has included a CAPM analysis, as his "Exh. KU-_5." In another recent case in which Dr. Avera participated as an ROE witness and included a CAPM analysis, the Commission stated that the company's "departure from that method [one-step DCF method] of analyzing an appropriate return on equity in its formula rate is unlikely to produce a just and reasonable result."[63] This policy is longstanding: the Commission has consistently found in the past that the CAPM is not an appropriate method for use in determining the appropriate ROE for an individual company.

> [T]he CAPM methodology, which relies on "beta," is not an appropriate mechanism for determining the ROE for an individual company. Trial Staff has identified a number of problems associated with estimating beta that make betas, in isolation, unreliable predictors of risk. Lastly, Mr. Moul's CAPM suffers from his use of long-term bond rates as his proxy of the risk-free

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[62] The Commission recently considered extensive comments on whether it should continue relying on DCF analysis to the exclusion of other methodologies, and decided that it should. Promoting Transmission Investment through Pricing Reform, Order No. 679, 71 Fed. Reg. 43,294 (July 31, 2006), III F.E.R.C. Stat. & Regs. ¶ 31,222, P 102 (2006) (to be codified at 18 C.F.R. §§ 35.34-35.35), *on reh'g*, Order No. 679-A, 72 Fed. Reg. 1,152 (Jan. 10, 2007), III F.E.R.C. Stat. & Regs. ¶ 31,236, *clarified*, 119 F.E.R.C. ¶ 61,062 (2007). While Dr. Avera notes in testimony filed December 7, 2007 in Docket No. ER08-313-000 that the Commission did not foreclose the use of other methodologies in its Order 679 and 679-A, Ex. XES-24 at 25, 48, it is much more telling to focus on what the Commission did: retain its DCF methodology.

[63] *Xcel Energy Sers., Inc.*, 122 F.E.R.C. ¶ 61,098, P 73 (2008) (citing *Consumers Energy Co.,* Opinion No. 429*,* 85 F.E.R.C. ¶ 61,100, at 61,361-62 (1998) and *System Energy Resources, Inc.*, Opinion No. 446, 92 F.E.R.C. ¶ 61,119, at 61,446 (2000)).

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> rate. The Commission has determined that the Treasury bill rate is a more appropriate proxy.

Consumers Energy Co., Opinion No. 429, 85 F.E.R.C. ¶ 61,100, at 61,361-62 (1998) (footnotes omitted). These criticisms, as well as others, are equally applicable to Dr. Avera's analyses in this proceeding.

There is no basis for the Commission to conclude differently here. While a CAPM might conceivably prove a useful check if DCF inputs had to be drawn from a period of extreme stock price turbulence (such as has been experienced this month), that quandary is not necessary for purposes of the present preliminary analysis.

Moreover, Dr. Avera's CAPM analysis is particularly suspect because it relies on a supposedly "risk-free" rate of 4.5% that reflects a 20-year maturity length and, thus, substantial inflation risk. It is generally recognized that the nearest thing to a "risk free" rate is the 3-month Treasury bill. Thus, Dr. Avera uses an erroneous benchmark yield. Also, Dr. Avera applies the DCF methodology to the 350 firms in the S&P 500 that pay dividends in order to calculate what he describes as the expected market rate of return. He then uses that rate of return to compute a "market risk premium" to which he applies Value Line betas for his proxy utilities to get a risk premium for each of his proxy companies. The Value Line betas he uses, however, are calculated using the New York Stock Exchange Composite Index as a measure for the market, not Dr. Avera's 350 selected companies. Thus, he mixes apples and oranges in calculating his market risk premium and his differently calculated measure of individual company risk and risk premium. Accordingly, the Commission should disregard Dr. Avera's CAPM analysis.[64]

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[64] To be clear, a well-designed CAPM analysis could serve a useful purpose if DCF data were not available, or if there were reason to conclude that the standard DCF methodology was not capable of producing credible results in a particular situation. But the fact that a CAPM study yields a higher indicated return than a DCF study is not such a reason.

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Dr. Avera' assertion that an adjustment of "13 to 37 basis points"[65] could be made for equity flotation costs is equally untenable. There is no reason to believe that KU plans to publicly float equity. Accordingly, clearly articulated Commission precedent precludes any flotation cost adjustment. *Enbridge Pipelines*, 100 F.E.R.C. ¶ 61,260, P 245 (2002) ("In order to receive this adjustment, the petitioner must provide actual evidence that such costs are expected to occur"); *Williston Basin Interstate Pipeline Co.*, 72 F.E.R.C. ¶ 61,074, at 61,377 (1995) ("A flotation cost adjustment is only proper if supported by actual test period evidence that such costs can be expected to be incurred"); *New England Power Co.*, 22 F.E.R.C. ¶ 61,123 (1983).

Accordingly, the Commission should disregard Dr. Avera's CAPM analysis and suggested flotation cost adjustment.

I. KU Has Not Properly Provided for Flow-Through of Environmental Characteristics Credits

Kentucky Municipals will be paying for a slice-of-system share of KU's entire generation portfolio — including any "green" resources included therein, and including the additional costs that KU incurs when it utilizes green resources instead of those that would be selected if only direct monetary costs were at issue (*e.g.,* plants fired by Kentucky coal). Wholesale customers purchasing and paying for slice-of-system power deserve a slice-of-system share of the associated environmental values.

When revenue requirements include the cost of renewable energy resources, any revenues resulting from the sale of renewable energy credits associated with those resources must be credited against those revenue requirements. *See Golden Spread Elec. Coop. v. Sw. Pub. Serv. Co.,* 123 F.E.R.C. ¶ 61,047, PP 111-12 (2008) ("when SPS sells renewable energy credits, it

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[65] KU Exhibit 5 at 56.

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must subtract the proceeds of these sales from the cost of the wind energy purchases it flows through the FCAC. Otherwise, SPS would not be including in the FCAC the true total cost of the purchase of wind power"). Similarly, when coordination power sale rates are cost-based such that they ought to include credits for power sale revenues, any revenues resulting from the explicit or implicit sale of emissions allowances should likewise be credited. Policy Statement and Interim Rule Regarding Ratemaking Treatment of Emissions Allowances in Coordination Rates, 59 Fed. Reg. 65,930, FERC Stat. & Regs. ¶ 31,009 (1994), *finalized*, 60 Fed. Reg. 22,257, FERC Stat. & Regs. ¶ 31,019 (1995). Where such allowances are in-kind (*i.e.,* are not sold for cash), the treatment of the in-kind allowances should mirror the treatment of cashed-out allowances. *See id.,* FERC Stat. & Regs. at 31,208. And the Commission has recognized that "'green' power certificates" such as "the environmental attributes of … wind generation" are merely "a by-product of its production of 'green' power for wholesale sale." *Madison Windpower, LLC,* 93 F.E.R.C. ¶ 61,270 at 61,871(2000).

Given that Kentucky Municipals will be paying for a slice-of-system share of KU's entire generation portfolio, they should share in any monetized or in-kind valuable byproducts of those resources. That is, they should share in both the revenue credits associated with green attributes of those resources that KU sells for cash, and any green attributes that KU elects not to sell off system.

J. KU's Proposed Tight Time Bar for Challenges to Formula Rate Inputs Is Contrary to Precedent and Unreasonable

The Commission "support[s] the use of review protocols for establishing a process for the orderly review of and challenges to the application of a formula rate during any annual update,"[66]

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[66] *Am. Elec. Power Serv. Corp,* 124 F.E.R.C. ¶ 61,306, P 31 (2008)

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and to its credit KU has proposed review protocols. However, its proposed protocols include a challenges time bar of the same kind that the Commission has previously rejected, made worse by an impracticably tight period for initiating a challenge.

Unless voluntarily extended by KU, customers would have only 60 days from each May 1 rate update[67] within which to investigate the update's inputs, and then only another 30 days to identify challenged inputs through a "Preliminary Challenge."[68] The scope of Preliminary Challenges arguably would constrain the scope of Formal Challenges, which would be due 21 days thereafter,[69] and absent a Formal Challenge or already-pending FERC proceeding, the update's inputs would become "final and no longer subject to challenge pursuant to these Annual Review Protocols or any other means by the FERC or any other entity."[70]

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[67] More precisely, the 90-day clock would start on the "Publication Date," which apparently would be either May 1 or, if May 1 fell on a weekend, the next business day. See ARA Sheet 17, Section 4.1.3.3.

[68] See ARA Appendix D, Section I.B.1.

[69] *See id.,* Section II.A (providing for Formal Challenges "If Seller and Customer have not resolved any Preliminary Challenge to the Annual Update within twenty-one (21) Days after the [90-day] Review Period").

[70] *See id.,* Section II.E, clause (i).

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This time bar is virtually word-for-word the same provision that was recently proposed by PSE&G and AEP,[71] and in each case rejected by the Commission. In *AEP*, the Commission explained that its

> long-standing precedent is that, under formula rates, parties have the right to challenge the inputs to or the implementation of the formula at whatever time they discover errors in the inputs to or implementation of the formula.[50] Indeed, customers may not uncover errors in data or imprudent or otherwise inappropriate costs until well after the challenge period.[51]
>
> ____
>
> [50] *North Carolina Electric Membership Cooperative v. Carolina Power & Light Co.*, 57 FERC ¶ 61,332, at 62,065 (1991) (rejecting the utility's efforts to limit the period of review to the prior 12 months by stating "[w]hile prompt identification of disputes is certainly a reasonable goal to strive for, the Commission cannot allow utilities to recover excessive rates through automatic adjustment clauses because the customer did not complain in as prompt a manner as the company believes the customer should have."). The Commission has held repeatedly that it may order refunds for past periods where a utility has either misapplied a formula rate or otherwise charged rates contrary to the filed rate. *See Appalachian Power Co.*, 23 FERC ¶ 61,032 at, 61,088 (1983); *DTE Energy Trading, Inc. v. Midwest Independent Transmission System Operator, Inc.*, 111 FERC ¶ 61,062, at P 28 (2005); *Quest Energy, L.L.C. v. The Detroit Edison Co.*, 106 FERC ¶ 61,227, at P 21 (2004).
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> [51] *See, e.g., Yankee Atomic Electric Co.*, 60 FERC ¶ 61,316, at 62,096-97 (1992) (allowing review of potentially imprudent costs charged to customers in prior-year formula rates).

AEP at P 35 (emphasis added). In *Public Service Electric & Gas Co.,* 124 F.E.R.C. ¶ 61,303, PP 15-22 (2008), the Commission explained that this policy against time-limiting formula rate challenges is rooted in the fact that formula inputs have never been submitted for Section 205 review, and "applies to all formula rates, regardless of type."

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[71] See *Am. Elec. Power Serv. Corp,* 124 F.E.R.C. ¶ 61,306, P 33 (2008) ("*AEP*").

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While Municipals would not necessarily insist upon a completely open-ended challenge period in the context of a mutual bar on overly delayed rate changes and otherwise reasonable protocols, the timeline proposed by KU is too tight. It is especially troubling that KU seeks to strictly time-limit prudence challenge rights, even while proposing to eliminate the partial requirements option that has long served as a check on the prudence and cost of KU's generation investments.[72] Accordingly, Municipals urge the Commission to either set this aspect of the protocols for hearing or settlement judge procedures, or reject it as it did in *AEP*.

K. KU's Proposals to Hide from Legal Accountability Are Unjustified and Unjustifiable

Without even noting these proposed changes, much less attempting to justify them, KU's proposed substitute terms and conditions attempt to make the Company virtually unaccountable. ARA Section 12.1 would allow KU to avoid its principal contractual obligation — to deliver the power for which Municipals will be paying millions of dollars — with "NO LIABILITY OF ANY KIND" unless the failure was due to "WILLFUL FAULT." Thus, KU would be immunized from the consequences of negligence, imprudence, or even gross recklessness. This demand for immunity is in marked contrast to KU's insistence that Municipals waive their own immunity.[73] Commission policy, however, is that vertically integrated public utilities should be accountable for the consequences of their negligence, to the full extent provided under state law.[74] That is, a federally-regulated tariff should not provide for narrowing (or expanding) the utility liabilities that would otherwise obtain under state law.[75]

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[72] *See* Part II.A.

[73] *See* ARA Section 12.3.

[74] *See* Order 890 P 1677.

[75] *See id.*

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Along with narrowing its substantive liability, KU also seeks to block the procedural channels provided for under state and federal law through which it could be held accountable.

First, KU seeks to mandate arbitration, even for disputes that would otherwise fall within this Commission's jurisdiction.[76] Although the Commission encourages voluntary arbitration, and although Municipals would certainly be open to arbitrating particular disputes for which that form of dispute resolution is well-suited, disputes can come in many forms, and the Commission has made clear that customers should not be forced to give up the judicial and regulatory litigation forums provided under state and federal law. *See Commonwealth Edison Co.,* 64 F.E.R.C. ¶ 61,253, at 62,784 (1993) ("[W]e see nothing to justify a utility to impose, over the customer's objections, a mandatory arbitration requirement in a tariff of general applicability."). Indeed, mandatory arbitration provisions have been voided as contrary to public policy.[77]

Second, for disputes that would otherwise go to a state or federal civil court, KU attempts to bar trial by jury. Here too, Commission policy is to leave intact the forums and remedies provided for under state law. *See Arkla Energy Res.,* 62 F.E.R.C. ¶ 61,076, at 61,511 (1993) ("This is a matter of contract law -- shippers should not be required to give up these rights; AERCo must delete this provision from the tariff.").

Third, KU seeks to steer those disputes that do somehow get to a court into a venue in Franklin County, rather than one closer to a particular affected Municipal or otherwise preferable under state law.[78] KU has not explained the basis for overriding the choice of forum law that would otherwise apply.

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[76] *See* ARA Section 11.4.

[77] *See Duke Power Co. v. FERC*, 864 F.2d 823, 830 (D.C. Cir. 1989).

[78] *See* ARA Section 12.5.2.

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The "representative model of the Existing Contracts"[79] that KU provides as Exhibit 2 contains none of these unjustified provisions. KU's proposal to add them should be rejected.

L. KU's Proposed Terms Should be Revised to Provide for Emergency Local Adjustment of KU Equipment, Under Agreed Procedures, to Protect Public Health and Safety

The first sentence of proposed ARA Section 3.8 includes (along with other prohibitions that are not in dispute) language flatly prohibiting Buyer from "mak[ing] any internal or external adjustments of any … piece of Seller's property wherever located." The second sentence of the same provision runs in the other direction, against KU adjusting Municipal property, but unlike the first sentence it contains an exception for "a prior written agreement." As filed, this provision is unreasonable in two regards.

First, the exception for a "prior written agreement" should apply to both the first sentence (concerning Municipals adjusting KU property) and the second sentence (concerning KU adjusting Municipal property). Municipals suspect that was KU's intent, but in any event this exception should be made reciprocal.

Second, the exception should be expanded somewhat (in both directions) by providing that consent to a prior written agreement designed to protect public health and safety will not be unreasonably withheld. As written, this language is capable of being applied in a way that would jeopardize public health and safety, and to that extent it is unreasonable. Public health and safety is of paramount importance, and is recognized as such in the Federal Power Act.[80]

KU's proposed language is not mere boilerplate, and was not inserted into KU's filing in a vacuum. It arises out of an ongoing dispute between KU and the City of Bardwell, which is

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[79] KU Transmittal Letter at 2 n.5.

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situated in far western Kentucky, near the Mississippi River, three hours' drive from KU's and E.ON US' headquarters in Lexington and Louisville, and far from the nearest KU personnel that can be relied upon to operate KU's equipment located at Bardwell in the event of an emergency. Situations have arisen and can be expected to continue arising in which good utility practice and protection of public health and safety in Bardwell demand that the switches at KU's interconnection to Bardwell be operated, and be operated with a shorter response time than the post-merger KU has been able to perform. Bardwell has personnel who are on the scene and competent to perform the needed operation, and is willing to accept liability for the consequences and have their personnel undergo any requisite KU training and certification. Some of the other Municipals are similarly situated.

The obvious, common sense solution to the affected municipals' distance from KU response personnel is to reach a written agreement under which appropriate municipal personnel will be trained and deputized to operate the necessary switches after receiving KU authorization to do so. Accordingly, Municipals ask that the Commission either include this issue within the scope of any hearing or Settlement Judge proceedings that may be instituted in this proceeding, or carve this issue out as one for mediation by the Commission's Dispute Resolution Service.

M. Either the Direct Assignment Facility Charges to Municipals, or the Flow-Through of Transmission Charges Paid By KU for Transmission to Municipals, Should Be Adjusted to Prevent Discriminatory Direct Assignment

In Docket No. ER08-1544, E.ON has filed, on behalf of KU and its affiliate LG&E, to modify its Open Access Transmission Tariff ("OATT") to end, but only as to new facilities, the Companies' existing practice of classifying certain delivery point facilities as direct assignment

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[80] *See* Federal Power Act Section 202(a)(2) (providing that state laws "designed to protect public health, safety, or welfare" take precedence over economic efficiency).

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facilities if used to serve only wholesale customers, but as rolled-in facilities if used to serve only KU retail load. That filing does not address the classification of existing facilities, which it tacitly admits is not comparable. For example, E.ON states that "[t]he purpose of the proposed OATT modifications related to E.ON U.S. LSE direct assignment facilities is to ensure that going forward if E.ON U.S. builds DAF for its unaffiliated and affiliated customers, E.ON U.S. will treat its own retail loads comparably in comparable situations." E.ON Transmittal Letter at 2, emphasis added. But it says nothing about "treat[ing] its own retail loads comparably in comparable situations" that involve existing facilities.

Direct assignment versus roll-in properly turns on whether facilities now serve a network function, not their vintage or "whether the facilities were installed to meet a particular customer's request for service." *Ne. Tex. Elec. Coop., Inc.*, 108 F.E.R.C. ¶ 61,084 P 47, *reh'g denied,* 111 F.E.R.C. ¶ 61,189 (2005); *see also Mansfield Mun. Elec. Dep't. v. New England Power Co.*, 97 F.E.R.C. ¶ 61,134, at 61,616 (2001) ("a rate disparity between the Municipals and others connected to [the core transmission system] … through similar facilities … is not justified"). Yet in determining roll-in versus direct assignment for existing facilities, E.ON appears to be rolling in facilities if used to serve only its retail customers, while in some cases directly assigning them if they are physically and electrically comparable but used to serve only wholesale customers.

Unless and until this discrimination is cured at its root through a revision of the E.ON OATT, the Commission should act here to ensure that KU and its affiliates cannot benefit from such discrimination. That is, it should modify KU's proposal to formulaically flow through E.ON's transmission charges, but directing KU not to flow through costs associated with facilities that are comparable to those for which Municipals pay direct assignment facility

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charges. Municipals currently lack the data needed to quantify the effect of this adjustment, but seek discovery rights to explore it, and point out here that it reinforces the need for a full suspension.

N. KU's Proposed Paris-Specific Terms Have Not Been Shown to Be Just and Reasonable

1. Penalty for failure to interrupt

Unlike the other Municipals, the City of Paris currently owns in-city generating units — a 12-MW plant consisting of seven diesel-powered units. In most hours, that plant is sufficiently large to serve Paris' entire load. Paris therefore currently serves its load using a combination of SEPA power, 3 MW of firm "deficiency" power sold by KU under the existing KU-Paris interchange agreement, and for the balance of its load, interruptible energy sold by KU, backstopped by Paris' internal generation, and priced at KU's energy charge. KU recognizes the interruptibility of the latter, calling it "Paris Interruptible" and removing it from the rate development in a manner that increases the "Total Annual Demand Revenue Requirement" that is collected through demand charges to Municipals for their firm power purchases. *See* Schedule A-1, line 7.

Consistent with this rate treatment, KU terms its deliveries up to the level backstopped by Paris' own generation "Secondary Service," and proposes that it have extensive rights to interrupt Secondary Service. Exhibit 3 of the filing sets forth KU's proposal to re-write the KU-Paris interchange agreement (redlined against the terms that would apply to the other Municipals). ARIA Section 3.4.1.1 thereof allows KU to interrupt Secondary Service for economic reasons, by notifying Paris that it should start its own generation to displace purchases from KU.

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Up to this point, KU and the Municipals are in agreement on the Paris-specific issues raised by KU's filing. However, because no generating plant is perfect, there is a risk that Paris' own generation will not operate when called upon, and that KU will therefore wind up serving Secondary Service load for a portion of what should have been an interruption. KU and the Municipals disagree sharply as to the proper rate consequences of such an event.

KU proposes that if such an event occurs in the eight summer or winter months (which are the only months when KU historically has exercised interruption rights and can be expected to do so in the future), it would bill Paris for 12 months of demand charges.[81] That is, KU would price service to Paris as firm requirements power, using the same demand and energy charge formula that applies to the other Municipals, in the amount of Paris' actual demand capped at "the total amount of Buyers' Secondary Service served by Seller during the interruption, up to twelve (12) MW." Notwithstanding this pricing, KU would retain the right to interrupt Paris during those 12 months (and thereafter), and thus would in fact be selling non-firm energy.

Under this provision, the consequence of failure to interrupt would be severe, apparently even if it resulted from an equipment failure that could not have been anticipated or prevented by Good Utility Practice. At the illustrative $7,908/MW-Month rate show in Exhibit 9, Schedule A-1, line 18, a one-hour failure to interrupt could result in charges exceeding $1.1 million.[82]

Municipals could understand such a steep penalty for an <u>intentional</u> failure to interrupt, but it would be draconian and not cost-justified if applied where Paris is unable to effect an interruption due to equipment breakdowns that are neither within its reasonable control nor due

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[81] See ARIA Section 3.4.3.1. In the unlikely event that KU unsuccessfully called for interruption in March, April, October, or November, KU would bill Paris for one month's demand charge. See ARIA Section 3.4.3.2.

[82] That is, $7,908/MW-month * 12 months * 12 MW = $1,138,752. Adjusting for load shape by using the Municipal aggregate KW/KWh ratio and Paris KWh shown at Exhibit 12, page 1, the charge would be slightly less, but would still equal $988,559.

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to negligence. Where KU is unable to deliver power due to such situations, it defines them as a "Force Majeure"[83] and relieves itself of any contractual obligation.[84] But where the Force Majeure affects generators owned by Paris, KU would specifically provide that "Force Majeure shall not be an excuse in the event that the Existing Paris Generation is unable to perform."[85]

In the comparable situation of a customer who is unable to interrupt non-firm transmission service, the Commission has made clear that penalties should be capped at twice the firm rate for the service period that encompasses the duration of the unreserved use.[86] Here, the analogous penalty would be no more than two months' demand charges, at the demand rate multiplied by the amount of demand usage during the failure to interrupt.

In a transparent effort to avoid comparison to this two-times penalty standard, KU characterizes its proposed penalty as a "ratchet" under which one month's demand usage establishes a minimum billing demand for the succeeding 12 months.[87] But the Commission's policy as to ratchets, when examined, does not avail KU either.

First, the penalty would not function like a ratchet. With a ratchet, while the customer is subject to a minimum bill for demand, it receives the capacity and is entitled to use it. In contrast, under KU's proposed terms, Paris would have to both pay for KU capacity and continue to keep Paris generation unloaded and available to start at KU direction.

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[83] See the definition of "Force Majeure" in ARIA Exhibit 3, Section 1.1.

[84] *See id.* at Section 3.5.

[85] *Id.,* Section 3.5(i).

[86] Order 890-A, FERC Stat. & Regs. ¶ 31,261, Preventing Undue Discrimination and Preference in Transmission Service, P 457 & n.183 (2008) (describing and affirming the Order 890 decision to "retain[] the current policy … that the unreserved use penalty rate may not be greater than twice the firm point-to-point rate for the period of unreserved use," and citing *Allegheny Power Sys., Inc.*, 80 F.E.R.C. ¶ 61,143, at 61,545–46 (1997)). Thus, a one-hour unauthorized use of firm service (for which the minimum standard service period is one day) will be penalized at twice the daily firm rate. Repeated violations can lead to longer duration multipliers. *See* Order 890, P 846.

[87] *See* Exhibit 4 (Seelye Testimony) at 26.

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Second, the traditional purpose of ratchets is to ensure that partial requirements customers who shave actual peaks, but oblige their supplier to plan for the possibility that they will take power during the 1 to 12 peak hours per year that drive capacity planning, contribute to the cost of the reserves that the supplier carries for that contingency. *See, e.g., Duke Power Co.,* Opinion No. 302, 43 F.E.R.C. ¶ 61,401 (1988) ("Opinion 302") (finding ratchet unjustified where the affected customers already paid for reserves). Here, KU admits that it "does not plan and/or construct its generation system to serve City of Paris' interruptible load, nor has it installed generation capacity to provide this service." Exhibit 4 (Seelye Testimony) at 26. Moreover, like the customers in *Opinion 302*, Paris supplements its own generation with purchases of firm service that includes the cost of reserves, and thus pays for an installed capacity margin that is available to meet multiple contingencies, including *force majeure* unavailability of customer-owned generation.

Third, if KU did supply capacity to Secondary Service load in the future, such supply might or might not coincide with the 12 monthly peak (12 CP) hours to which the proposed formula[88] would look in allocating demand charges to the Municipal class. If the supply was coincident, it would increase the demand revenue requirement to be recovered from the Municipal class, and KU would therefore enjoy twelve months of increased recovery. KU's proposed "ratchet" fails to account for this allocation effect, and therefore would effect a double-recovery. If the supply was non-coincident, then the peak-coincident installed capacity margin for which the Municipal class pays presumably would suffice to provide the needed capacity. But because KU bills Municipals for demand based on their non-coincident peaks, such non-coincident demand would nonetheless give rise to penalty charges. In this respect, Witness'

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Seelye's testimony (KU Exhibit 4 at 26) that "the 11-month ratchet is applied precisely when" Paris "places a demand on the system at peak times" is misleading. The ratchet would apply if Paris placed a demand on the system outside of the 12 monthly peak hours that drive system planning.

Even so, in the unlikely event the installed capacity margin for which Paris and the other Municipals pay turns out to be insufficient, such that KU actually has to purchase generation specifically for the purpose of covering a standby obligation to Paris, perhaps it would be reasonable for KU to be held harmless. That is, perhaps it would be appropriate to flow through to Paris the net incremental cost of that purchase, after crediting any revenues received from the sale of the purchased power and energy to others. But KU has not made any such purchase; it has merely hypothesized that it conceivably might have to do so.

For the foregoing reasons, the penalty charge to Paris in the event of a *Force Majeure* failure to interrupt should be capped at, at most, the higher of two months' demand charges or the actual and prudent net cost[89] of incremental resources that KU purchases to cover such failure.

2. Re-synchronization exemption from penalty

There is a technical drafting issue related to the penalty issue discussed in Part II.N.1 above. To explain it, some operational background is necessary.

Breakers enable Paris and KU to disconnect in response to transmission system disturbances, such as are caused by lightning strikes. In order to re-close the connection, Paris must first temporarily shut down its internal generation, lest the breakers close with that

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[88] *See* Exhibit 9, Schedule A-1, line 9.

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generation operating out of phase with KU's system. Such shutdowns typically take a quarter-hour or less, and are a necessary, good utility practice aspect of re-closing the connections. Accordingly, they should not trigger failure-to-interrupt penalties, even if they occur during a period when KU is otherwise calling on Paris to interrupt.

Proposed ARIA Section 3.4.3.3 appears to provide for such an exemption, but would benefit from a clarification. It provides:

> If Seller exercises its rights pursuant to Section 3.4.1.1, and Buyer is unable to operate the Existing Paris Generation due to an interruption of the Seller's connection to the Buyer's generation substation requiring the Buyer to disconnect, re-start and re-connect its Existing Paris Generation (after the seller's interconnection has been restored) Buyer's Capacity Credit shall not be reduced for the period of interruption; provided, however, that once the Seller's interconnection has been restored Buyer shall restart and re-connect the Existing Paris Generation to serve Buyer's Retail Load as quickly as possible using Good Utility Practice. Buyer's failure to operate Existing Paris Generation within one hour after the Seller's interconnection has been restored shall result in a reduction of Buyer's Capacity Credit pursuant to either Section 3.4.3.1 or Section 3.4.3.2, as applicable.

In other words, if a period when KU calls on Paris to operate its internal generation coincides with a period when the Paris-KU connection is interrupted, the capacity credit "shall not be reduced for the period of interruption," provided Paris gets its generation back on line promptly. The capacity credit will be reduced if Paris can't get its generation back on line within an hour after the breakers are re-closed.

The wording problem here, which we assume is a technical drafting error, is that the period of concern is the time immediately <u>following</u> the "period of [the connection's] interruption," not the time <u>within</u> the period when the connection remains open. With or without

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[89] To the extent KU has other uses for such resources after purchasing them on Paris' account, the value of such other uses should be subtracted in determining those resources' net cost.

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the ARIA Section 3.4.3.3 exemption, there would be no penalty charge incurred within that period, because while the connection is open, KU is not "serv[ing] Buyer's Secondary Service" within the ambit of Sections 3.4.3.1-2. To avoid this superfluity, and to honor the specific provision for a one-hour grace period in the last sentence of Section 3.4.3.3, the language filed by KU would be better read as providing that the time when Paris' internal generation is disconnected will not give rise to penalty charges either. To avoid an unnecessary ambiguity, however, "shall not be reduced for the period of interruption" clause should be revised to read "shall not be reduced due to the disconnection of Existing Paris Generation."

3. Three-year notice for termination as to Paris

Although KU proposes a five-year termination notice period for application to the other Municipals, it proposes a three-year period for Paris.[90] The only basis offered for the distinction is that the existing Paris-KU Interchange Agreement contains a three-year termination notice period. That would be a persuasive distinction if KU were otherwise proposing to maintain the distinct terms of that existing agreement, but in fact KU is proposing to conform its Paris agreement to the other Municipals' agreements in virtually all regards. KU has not explained why its contract term with Paris (and vice-versa) should be shorter than its contract term with the other Municipals.

4. Obligation to provide and maintain transformers

In ARIA Section 3.1.5, KU proposes that Paris be responsible for providing and maintaining "all transformers and other facilities needed by Buyer to take service at the Delivery Points(s) at the delivered voltage, as specified in Appendix A." If this provision means that KU will deliver at the locations and voltages specified in Appendix A and it is up to Paris to take the

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[90] *See* Transmittal Letter at 17 and ARIA Section 2.3.1. (In both cases, we refer to termination effective after 2015.)

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electricity from there to load, that is unobjectionable. But if this provision is meant to make it Paris' responsibility to transform electricity to the voltages specified in Appendix A (e.g., in the event KU were to change the voltage on its side of the delivery point), it would represent an unexplained and unjustified change to the existing Interchange Agreement, and should be rejected.

5. Conflated delivery points in ARIA Appendix A

In Exhibit 3, ARIA Appendix A, the "Points of Interconnection, *i.e.,* Delivery Points" include as a single point a 69 kV point labeled "Scott St./ Claysville Location of Paris' generating station." This item conflates two distinct 69 kV delivery points that should be broken out separately, as (a) Scott Avenue (at the location of Paris' generating station), and (b) Claysville.

III. REQUEST FOR REJECTION OR SUMMARY DISPOSITION

As shown above, the filing violates generally-applicable Commission policy and filing regulations that should not be waived. It also lacks adequate cost support and revenue projections. It should be rejected as patently deficient, and if not rejected, should be summarily modified to cure the flaws identified above.

IV. ALTERNATIVE REQUEST FOR FULL FIVE-MONTH SUSPENSION

Using a 2007 test year for illustration, KU proposes to increase its annual billings to Municipals by about $4.8 million.[91] The share of this increase that has not been shown to be just and reasonable considerably exceeds 10%. As shown in Attachment 1, applying KU's 2007 test year, the cumulative effect of just five of the well-supported adjustments discussed above is to reduce the aggregate cost of service to $82,078,729, which is more than $8 million <u>less</u> than the

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[91] See Attachment 1 hereto and note 21 above.

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$90,092,668 that KU shows[92] as the amount charged under current rates. Thus, in the test year selected by KU for its rate comparison, the proposed increase is 186% excessive, considerably exceeding the $480,000 level that represents 10% of the expected increase. And that is before accounting for the fact that the increase in actual application during 2009 will likely be even larger, and also before accounting for the more difficult-to-quantify effects of the proposed term and condition changes. The *West Texas*[93] test for maximum suspension is therefore met, and then some. KU's filing should be suspended for the maximum five months beyond the requested December 1, 2008 effective date, to May 1, 2009.

Public utilities seeking rate increases sometimes suggest that suspension is an unnecessary remedy, because any excess can be refunded. But even with refunds, yanking a rate up and down without justification harms municipalities that take requirements service, and their customers and citizens. As not-for-profit local government institutions, municipal requirements customers must recover their costs from their retail customers on an ongoing basis, and are often relied upon to fund local government operations. Refunds may be long delayed, do not compensate wholesale customers and their downstream retail consumers for the disruptive effects of a rate increase, and do nothing to discourage utilities from overreaching in their initial filings. That is why the Federal Power Act provides not only for refunds but for suspension as well, and why the longstanding *West Texas* test calls for both remedies to be applied where a preliminary review indicates that the filing utility has substantially over-reached, as KU has done here.

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[92] See KU Exhibit 12 at 1 (last row, last column).

[93] *W. Tex. Utils. Co.*, 18 F.E.R.C. ¶ 61,189, at 61,374 (1982) (Rates are "substantially excessive," calling for maximum suspension, where it appears that at least 10 percent of the proposed increase is excessive).

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V. ALTERNATIVE REQUEST FOR HEARING

To the extent not rejected or summarily modified, KU's filing should be set for trial-type evidentiary hearing. KU has not demonstrated beyond genuine dispute of material fact that its rate filing meets statutory, regulatory, and contractual requirements.

VI. CALL FOR SETTLEMENT JUDGE MEDIATION

As KU notes, as KU was preparing its filing, KU and the Municipals met on several occasions to discuss regarding rates, terms, and conditions. See Transmittal Letter at 1 n.4. Although those discussions did not lead to a complete agreement, they were successful and worthwhile in narrowing the extent of disagreement. Municipals believe that further negotiations could further narrow the parties' disagreements. To facilitate such progress, Municipals request the designation of a Settlement Judge.

VII. CONCLUSION

WHEREFORE, the Commission should consider Kentucky Municipals' Protest and dispose of KU's filing as recommended above:

Respectfully submitted,

/s/ David E. Pomper

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Attorneys for Kentucky Municipals
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October 20, 2008

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Attachment 1

Kentucky Utilities Company
FERC Docket ER08-1588-000
Kentucky Municipals - Summary Cost of Service Adjustments

Line	Description	Demand-Related	Energy-Related [1]	Total	Difference	Precent of Requested Increase [2]	Cumulative Difference	Cumulative Percent of Requested Increase [2]
1	Cost of Service as Filed	31,734,469	59,261,588	90,996,057			-	
2	COS Excluding CWIP	25,286,102	59,261,588	84,547,690	(6,448,367)	-134%	(6,448,367)	-134%
3	COS with 1/2 of Account 926 Expenses Removed (PBOP estimate)	24,944,550	59,001,209	83,945,759	(601,931)	-13%	(7,050,298)	-147%
4	COS using average of Beginning and End of Year Plant Balances	24,276,173	58,993,947	83,270,121	(675,639)	-14%	(7,725,937)	-161%
6	COS at 10.2% Return on Equity	23,170,739	58,907,989	82,078,729	(1,191,392)	-25%	(8,917,329)	-186%

[1] Assumes an energy allocation factor of 9.19%
[2] Based on Requested Increase of $4,799,775.
See KU Exhibit 12 at 2, last row, last col.

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Kentucky Utilities Company
FERC Docket ER08-1588-000
Kentucky Municipals - Summary Cost of Service Adjustments

Revenue Under Current Rates	90,092,668
Revenue Under Proposed Rates (including OATT and Facilities Charges)	94,892,443
Proposed Revenue Increase	4,799,775
Sum of Adjustments by Kentucky Municipals	(8,917,329)
Sum of Adjustments as Percent of Proposed Revenue Increase	-186%

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Attachment 2

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Executive Director
Kentucky Public Service Commission
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PUBLIC SERVICE COMMISSION

April 21, 2008

RE: The 2008 Joint Integrated Resource Plan of Louisville Gas and Electric Company and Kentucky Utilities Company
Case No. 2008-00148

Dear Ms. Stumbo:

Pursuant to 807 KAR 5:058, Louisville Gas and Electric Company (LG&E) and Kentucky Utilities Company (KU) hereby file the 2008 Joint Integrated Resource Plan (IRP) of LG&E and KU.

Accompanying the IRP filing is a Petition for Confidential Protection relating to projected power production costs and projected sales rates. Therefore, the Companies are filing with the Commission ten (10) bound copies and one (1) unbound copy from which the information sought for confidential treatment has been redacted. Another copy is filed highlighting the information for which confidential treatment is sought.

Sincerely,

Rick E. Lovekamp

Enclosures

cc: Hon. Dennis Howard II
Hon. Michael L. Kurtz

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Combined Company sales and energy requirements are expected to grow at an average annual rate of 1.5 percent over the period between 2008 and 2012. Over the next five-year period (2013-2017), the average annual growth in sales and energy requirements declines to 1.0 percent due primarily to reductions in lighting-related consumption prompted by ESA 2007 (see Section 6 for a more detailed discussion of ESA 2007). Over the entire forecast period, the average annual growth in sales and energy requirements is 1.3 percent.

Table 5.(3)-2
Combined Company: Forecast Customer Numbers, Sales, and Energy Requirements

Year	Combined Company Customers	% Growth in Customers	Combined Company Sales Forecast (GWh)[1]	% Growth in Energy Sales	Combined Company Energy Requirements Forecast (GWh)[1]	% Growth in Energy Requirements
2007	934,227		33,705		35,758	
2008	944,906	1.1%	34,731	3.0%	36,835	3.0%
2009	957,148	1.3%	35,267	1.5%	37,404	1.5%
2010	969,313	1.3%	35,754	1.4%	37,921	1.4%
2011	981,218	1.2%	36,328	1.6%	38,531	1.6%
2012	992,836	1.2%	36,843	1.4%	39,080	1.4%
2013	1,004,189	1.1%	37,268	1.2%	39,535	1.2%
2014	1,015,777	1.2%	37,629	1.0%	39,927	1.0%
2015	1,027,618	1.2%	37,967	0.9%	40,298	0.9%
2016	1,039,507	1.2%	38,332	1.0%	40,695	1.0%
2017	1,051,341	1.1%	38,761	1.1%	41,153	1.1%
2018	1,063,311	1.1%	39,298	1.4%	41,725	1.4%
2019	1,075,417	1.1%	39,812	1.3%	42,270	1.3%
2020	1,087,662	1.1%	40,418	1.5%	42,914	1.5%
2021	1,100,047	1.1%	40,923	1.2%	43,449	1.2%
2022	1,112,574	1.1%	41,477	1.4%	44,036	1.4%

[1]2007 sales and energy requirement figures are weather-normalized actual values.

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Attachment 3

Kentucky Utilities Company
Docket No. ER08-1588-000
Adjustments to Dr. William E. Avera's Electric Utility Proxy Group
FERC DCF Model Results

Line No.	Company	Standard & Poor's Corporate Credit Rating	Moody's Issuer or Senior Unsecured Rating	Exhibit KU-__3 Per Avera Implied Cost of Equity Low	Exhibit KU-__3 Per Avera Implied Cost of Equity High	"Adjusted Range of Reasonableness" Per Avera Implied Cost of Equity Low	"Adjusted Range of Reasonableness" Per Avera Implied Cost of Equity High	Companies With An Illogical Result Removed Implied Cost of Equity Low	Companies With An Illogical Result Removed Implied Cost of Equity High	BBB+ Rated Utilities Only Implied Cost of Equity Low	BBB+ Rated Utilities Only Implied Cost of Equity High
1	**ALLETE**	**BBB+**	Baa1	9.2%	10.9%	9.2%	10.9%	9.2%	10.9%	**9.2%**	**10.9%**
2	**Alliant Energy**	**BBB+**	A3	9.1%	9.7%	9.1%	9.7%	9.1%	9.7%	**9.1%**	**9.7%**
3	American Elec Pwr	BBB	Baa2	9.7%	10.5%	9.7%	10.5%	9.7%	10.5%		
4	Cleco Corp.	BBB	Baa3	9.1%	18.2%	9.1%					
	Constellation Energy										
5	Dominion Resources	A-	Baa1	11.9%	13.3%	11.9%	13.3%	11.9%	13.3%		
6	DPL, Inc.	BBB	A3	14.3%	15.6%	14.3%	15.6%	14.3%	15.6%		
7	DTE Energy Co.	BBB	Baa2	7.8%	11.5%		11.5%	7.8%	11.5%		
8	Duke Energy	A-	Baa2	7.1%	10.0%		10.0%	7.1%	10.0%		
9	Entergy Corp.	BBB	Baa3	11.5%	15.4%	11.5%	15.4%	11.5%	15.4%		
10	FirstEnergy Corp.	BBB	Baa3	10.8%	11.5%	10.8%	11.5%	10.8%	11.5%		
11	Great Plains Energy	BBB	Baa2	7.5%	14.5%		14.5%	7.5%	14.5%		
12	Hawaiian Electric	BBB	Baa1	7.3%	11.1%		11.1%	7.3%	11.1%		
13	IDACORP, Inc.	BBB	Baa2	7.7%	10.2%		10.2%	7.7%	10.2%		
14	Integrys Energy Group	A-	A3	8.1%	18.2%	8.1%					
15	Northeast Utilities	BBB	Baa2	8.9%	11.4%	8.9%	11.4%	8.9%	11.4%		
16	**Otter Tail Corp.**	**BBB+**	A3	7.9%	11.0%		11.0%	7.9%	11.0%	**7.9%**	**11.0%**
17	**PG&E Corp.**	**BBB+**	Baa1	9.7%	11.3%	9.7%	11.3%	9.7%	11.3%	**9.7%**	**11.3%**
18	**Portland General Elec.**	**BBB+**	Baa2	8.1%	10.8%	8.1%	10.8%	8.1%	10.8%	**8.1%**	**10.8%**
19	PPL Corp.	BBB	Baa2	10.3%	20.1%	10.3%					
20	**Progress Energy**	**BBB+**	Baa2	7.8%	12.2%		12.2%	7.8%	12.2%	**7.8%**	**12.2%**
21	P S Enterprise Group	BBB	Baa2	12.6%	15.1%	12.6%	15.1%	12.6%	15.1%		
22	SCANA Corp.	A-	Baa1	9.7%	10.2%	9.7%	10.2%	9.7%	10.2%		
23	**Sempra Energy**	**BBB+**	Baa1	9.5%	10.7%	9.5%	10.7%	9.5%	10.7%	**9.5%**	**10.7%**
24	Vectren Corp.	A-	Baa1	8.5%	10.4%	8.5%	10.4%	8.5%	10.4%		
25	**Wisconsin Energy**	**BBB+**	A3	9.3%	11.9%	9.3%	11.9%	9.3%	11.9%	**9.3%**	**11.9%**
26	**Xcel Energy, Inc.**	**BBB+**	Baa1	8.6%	11.1%	8.6%	11.1%	8.6%	11.1%	**8.6%**	**11.1%**
	Range			7.1%	20.1%	8.1%	15.6%	7.1%	15.6%	**7.8%**	**12.2%**
	Midpoint			13.6%		11.9%		11.4%		**10.0%**	
	Median			**10.5%**		**10.8%**		**10.5%**		**9.7%**	

Source: Ex. KU-_3, Page 1 of 1, in Docket No. ER08-1588.

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CERTIFICATE OF SERVICE

I hereby certify that I have on this 20th day of October, 2008, caused the foregoing document to be sent to all parties on the list compiled by the Secretary of the Commission in this proceeding.

/s/ David E. Pomper

David E. Pomper

Law Offices of:
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(202) 879-4000

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CERTIFICATE OF SERVICE

I hereby certify that I have on this 27th day of October, 2008, caused the foregoing document to be sent by electronic mail to all addressees on the official service list for Docket No. ER08-1588 and to the contacts for the Respondent as listed on the Commission's list of Corporate Officials, as follows:

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/s/ *David E. Pomper*
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