COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

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PUBLIC SERVICE COMMISSION

In the Matter of:

THE APPLICATION OF EAST KENTUCKY	)
POWER COOPERATIVE, INC. FOR	)
A CERTIFICATE OF PUBLIC	)
CONVENIENCE AND NECESSITY TO	) **CASE NO. 2005-00207**
CONSTRUCT A 161 KV TRANSMISSION LINE	)
IN BARREN, WARREN, BUTLER, AND	)
OHIO COUNTIES, KENTUCKY	)

APPLICANT'S RESPONSE TO COMMISSION STAFF'S FIRST DATA REQUEST DATED AUGUST 18, 2005

EAST KENTUCKY POWER COOPERATIVE, INC.

PSC CASE NO. 2005-00207

INFORMATION REQUEST RESPONSE

COMMISSION'S FIRST DATA REQUEST DATED 8/18/05

ITEM 1

RESPONSIBLE PARTY: MARY JANE WARNER

REQUEST: What were the responses of the Midwest Independent System Operator ("MISO"), Louisville Gas & Electric Energy ("LGEE"), Tennessee Valley Authority ("TVA"), and Big Rivers Electric Corporation to East Kentucky Power's proposed transmission expansion plan?

RESPONSE: EKPC began discussions with TVA in March 2004 concerning the proposed plan to serve WRECC. TVA declined EKPC's request for the three proposed interconnections in August 2004. EKPC subsequently filed an application with FERC to order the requested interconnections. FERC issued a Proposed Order Directing Interconnection in April 2005. A Final Order Directing Interconnection was issued by FERC on August 3, 2005 (attached as **Exhibit 1-1**).

EKPC involved Big Rivers Electric Corporation (BREC) in the study early in the process, since it was clear that an interconnection with BREC would be required to provide the support necessary to aid in serving the WRECC load. EKPC and BREC are in agreement that the interconnection is beneficial for both parties, and therefore justified. Additionally, BREC identified no adverse impacts on its system caused by the EKPC

Project (see the attached **Exhibit 1-2**, which is a letter from BREC to EKPC dated April 18, 2005).

EKPC brought LGEE and the MISO into the process in August 2004. A draft of the study report and the power flow models used in the studies were provided at that time. A conference call was then conducted in September 2004 to discuss the status of the study and garner input from LGEE and the MISO. MISO invited Cinergy (CIN), Hoosier Energy (HE), and Vectren to participate in the conference call; only HE chose to do so.

LGEE provided some input regarding the models and issues to be considered. EKPC updated its studies based on some of the comments received, and redistributed the results. LGEE was given opportunity to comment on the final draft of the report in January 2005. The LGEE response raised one issue that EKPC had chosen not to address in its study. EKPC modeled the forecasted WRECC loads to be served via the LGEE transmission system from its Leitchfield 69 kV bus in 2010 Summer. This expected peak demand is 46.5 MW. LGEE indicated that the existing contractual limit with TVA for this delivery point is 35 MW. LGEE felt that EKPC should not model more than 35 MW at this delivery point. However, EKPC chose to model the expected demand of 46.5 MW to determine the impacts on the transmission system of serving the expected Warren load. Since the 35 MW limit is part of a TVA/LGEE agreement, EKPC is not bound by that limit. A study will be required to determine the system upgrades, if any, necessary for LGEE to provide transmission service for the expected WRECC load level for the stations connected to LGEE's Leitchfield 69 kV bus. EKPC will make a request by the end of 2005 for transmission service from MISO/LGEE for these Warren loads, and any issues associated with that request will be addressed during that study process.

MISO performed an independent assessment of the EKPC plan for service to WRECC. A draft of the study results was provided to EKPC. The only specific conclusion drawn from this draft was that the EKPC Project has little impact on LGEE voltages. The results indicate that line and transformer flows for MISO in the vicinity of the EKPC Project are not impacted. Impacts were observed in the area around JK Smith due to EKPC's assumed additions at that site. However, these results are the subject of a separate ongoing study, and thus should not be addressed as part of the EKPC Project to serve WRECC. MISO has provided no additional response beyond the initial draft documenting its independent analysis.

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Joseph T. Kelliher, Chairman;
Nora Mead Brownell, and Suedeen G. Kelly.

East Kentucky Power Cooperative, Inc. — Docket Nos. TX05-1-000, TX05-1-001, TX05-1-002

ORDER DIRECTING THE FILING OF AN INTERCONNECTION AGREEMENT AND REVISED SYSTEM IMPACT STUDIES

(Issued August 3, 2005)

1. This order directs the Tennessee Valley Authority (TVA) to file the rates, terms, and conditions under which it will interconnect with East Kentucky Power Cooperative, Inc.'s (EKPC) system, pursuant to sections 210 and 212 of the Federal Power Act (FPA),[1] and provide coordination services necessary for EKPC to deliver energy to Warren Rural Electric Cooperative Corporation (Warren). This order also directs TVA and EKPC to file revised System Impact Studies reflecting the modified interconnection request submitted by EKPC as discussed in this order.

I. Background

2. EKPC is an electric generation and transmission cooperative in Kentucky. It supplies electric power to its electric distribution cooperative members that serve retail electric customers in central and eastern Kentucky.[2]

3. TVA is a wholly-owned corporate agency and instrumentality of the United States

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[1] 16 U.S.C. §§ 824i and 824k (2000).

[2] As a cooperative with outstanding Rural Utilities Service debt, EKPC is not a Commission-jurisdictional public utility, but it has a reciprocity Open Access Transmission Tariff on file with the Commission. *East Kentucky Power Cooperative, Inc.*, Docket No. NJ97-14-000, unpublished letter order dated December 17, 1997.

government organized under the Tennessee Valley Authority Act of 1933.[3] TVA produces and sells electric power in seven states[4] at wholesale for resale to municipal and cooperative distributors and at retail to large industrial customers and to several government facilities. TVA owns and operates an extensive transmission system that is interconnected with the transmission systems of neighboring electric utilities, including EKPC's transmission system. EKPC currently is interconnected to TVA's transmission system at six locations.

4. Warren is a distribution cooperative serving approximately 54,000 customers in south central Kentucky.[5] TVA provides Warren with the electric power Warren needs to serve its customers through five delivery points on TVA's transmission system.[6] As provided in the Warren/TVA Power Contract covering provision of this service, Warren notified TVA that it would terminate the agreement on April 1, 2008. At that time, EKPC will begin supplying electric power to Warren under a 33-year full-requirements wholesale power contract. TVA rejected EKPC's proposals for EKPC to purchase transmission service from TVA in order to move power from EKPC to Warren.

5. On October 1, 2004, EKPC filed an application for a Commission order under sections 210 and 212 of the FPA directing TVA to interconnect its system to the EKPC system in order to allow EKPC to provide full requirements service to Warren following the termination of Warren's existing power contract with TVA on April 1, 2008 (Application). In the Application, EKPC proposed to construct approximately 90 miles of 161 kV transmission line[7] and three free flowing interconnection points between the

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[3] 16 U.S.C. §§ 831-831dd (2000) (TVA Act).

[4] Alabama, Georgia, Kentucky, Mississippi, North Carolina, Tennessee and Virginia.

[5] Warren operates 5,000 miles of 13 kV distribution facilities, 200 miles of 69 kV sub-transmission facilities and 37 substations, including eight delivery point stations.

[6] Aberdeen Gap, East Bowling Green, Bristow, Memphis Junction and Franklin.

[7] The 161 kV transmission line as proposed in the Application includes: (1) 25 miles of line from EKPC's Barren County Substation to the Warren System at the General Motors Substation; (2) 25 miles of line from the Aberdeen Substation to the Big Rivers Electric Corporation's Wilson 161 kV Substation; (3) 40 miles of line between the General Motors, Memphis Junction, and Aberdeen Substations to form a 161 kV network between Barren County and Wilson.

systems of EKPC and TVA.[8] EKPC explained that it would need three new interconnections with the TVA transmission system for reliability purposes, and in order to facilitate its request for coordination services from TVA.[9]

6. TVA responded with several objections to the proposed interconnection and the method EKPC proposed to evaluate the interconnection, arguing that: (1) the request for interconnection is actually an attempt to obtain transmission service over TVA's transmission system, circumventing section 212(j) of the FPA, which prohibits the Commission from ordering transmission service under section 211 of the FPA; (2) EKPC's proposal does not meet the statutory requirements for an interconnection order under section 210 of the FPA; and (3) the System Impact Study Base Case should reflect the system as it will exist without Warren, rather than the status quo.

7. On April 14, 2005, the Commission issued a proposed order under sections 210 and 212 of the FPA requiring TVA to interconnect its transmission system at the three requested points.[10] In the Proposed Order, the Commission found that section 210(c) requires that in order for the Commission to order an interconnection it must find that the interconnection is in the public interest and that the proposed interconnection will meet at least one of the three specified criteria, *i.e.,* it will encourage conservation of energy or capital, optimize efficiency of facilities and resources, or improve the reliability of any electric utility system to which the order applies.[11] The Commission found that EKPC met these standards because: (1) the requested interconnections would enable EKPC to

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[8] The interconnections between EKPC and TVA as proposed in the Application were at three existing substations: East Bowling Green, Memphis Junction, and Franklin.

[9] Section 210 of the FPA provides that, in addition to ordering the physical interconnection of facilities, the Commission is also authorized to order "such sale or exchange of electric energy or other coordination, as may be necessary to carry out the purposes of any order" issued under section 210 (emphasis added). *See* 16 U.S.C. §§ 824i(a)(1)(A) and 824i(a)(1)(C) (2000). EKPC's Application requested "any additional coordination services required to maintain these interconnections." *See* Application at 9. In its May 31 Brief, EKPC states that the existing Interconnection Agreement between EKPC and TVA already provides for the coordination services contemplated by EKPC in its Application, specifically voltage support and, in the event of a contingency, additional backup service.

[10] *East Kentucky Power Coop., Inc.*, 111 FERC ¶ 61,031 (2005) (Proposed Order).

[11] *Id.* at P 37.

enlarge its membership and to optimize the use of system resources; (2) the requested interconnections would encourage the conservation of energy and capital by providing Warren with access to more economical sources of power; and (3) the requested interconnections would optimize the use of existing facilities by allowing increased competition.[12] The Commission, therefore, concluded that it was in the public interest to issue a proposed order directing interconnection, ordered further procedures to establish the terms and conditions of the proposed interconnection, and offered settlement judge procedures to facilitate the parties' negotiations.

8. Section 212(c)(1) provides that, before issuing a final order under section 210, the Commission issue a proposed order setting a reasonable time for the parties to agree to terms and conditions for carrying out the order, including the apportionment of and compensation for costs. Thus, the Proposed Order provided that, if the parties were able to agree, the Commission would issue a final order reflecting the agreed-upon terms and conditions in that agreement, if the Commission approves of them. In the alternative, if the parties were unable to agree within the allotted time, the Commission would evaluate the positions of each party and prescribe the apportionment of costs, compensation, terms, and conditions of interconnection, if appropriate.

9. The Commission gave EKPC and TVA 30 days from the date of issuance of the Proposed Order to negotiate the terms and conditions for the new interconnection, consistent with section 212. The Commission also required EKPC and TVA to submit to the Commission, within 15 days after the expiration of the 30-day negotiation period, all terms and conditions on which they had mutually agreed, accompanied by explanations. The Commission directed that, if there were matters still in dispute, the parties should also file briefs to support their final positions, accompanied by any necessary supporting data. The Commission offered settlement judge procedures to assist the parties in resolving the matter. Finally, the Commission declined TVA's request to establish an evidentiary hearing, explaining that it was premature at the time of the Proposed Order to do so. The Commission stated that, if EKPC and TVA could not reach a mutual resolution in the 30-day negotiation period, and there were issues of material fact in dispute, the parties could make arguments for such an evidentiary hearing when they filed their briefs to the Commission. Finally, the Commission agreed with EKPC that the Base Case study should reflect the status quo.[13]

[12] *Id.* at P 38.

[13] *Id.* at P 40.

10. The parties were unable to reach any agreement on the terms and conditions of the proposed interconnection directed in the Proposed Order. As a result, following expiration of the 30-day negotiation period provided in that order, the parties filed briefs with the Commission on May 31, 2005.[14]

II. Parties' Briefs

A. EKPC's May 31 Brief

11. In its May 31 Brief, EKPC proposes that the requested interconnections be facilitated through amendments to an existing interconnection agreement (Existing IA) between the parties (Proposed Amendments). In addition, EKPC now proposes modifications to the physical interconnections in its initial proposal, including a shift of one of the interconnection points (which, in its Application, was at Franklin) to Salmons. EKPC states that the Proposed Amendments are consistent with previous additions of interconnections, and do not materially change the terms of the agreement. The Proposed Amendments obligate EKPC to reimburse TVA for costs associated with the installation, operation and maintenance of the interconnection facilities, and provide for the coordination services requested by EKPC. EKPC argues that the Commission can order coordination services for the proposed interconnection under section 210(a)(1)(C) of the FPA. EKPC further argues that voltage support is requested (with a compensation structure proposed) only to avoid duplication of facilities; and that the requested back-up power service obligates TVA to provide power only as-available, and does not obligate TVA to incur any costs to ensure that it can deliver such back-up power. Finally, EKPC argues that an evidentiary hearing is not required since the parties' disagreements are only based on legal matters, not factual disputes.

12. EKPC also includes an affidavit of Darrin Adams, who testifies: (1) that EKPC's new changes to their proposal are only minor and resolve the overload of a transformer during certain contingencies, and create no adverse effects; (2) that TVA's previous assertion that certain portions of the transmission systems would be negatively impacted by the proposal is incorrect (the identified overloads either are actually relieved by the changes to the proposal and/or exist regardless of the added interconnection); (3) that TVA's claim that EKPC's load at Franklin is completely served by TVA is incorrect (load is actually served from other EKPC substations, not TVA's Franklin substation);

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[14] EKPC supplemented its May 31 Brief with filings made on June 1, 2005 and June 2, 2005.

and (4) that TVA's claim of a 731 MW reduction in export capability exists only if the base case proposed by TVA is used, which the Commission rejected in its guidance on the System Impact Study Base Case.

B. TVA's May 31 Brief and July Response

13. TVA argues that EKPC's request for interconnection is the equivalent of a request for transmission service over TVA's system. TVA points out that the Commission's section 211 authority when applied to TVA is limited by section 212(j). According to TVA, section 212(j) specifically provides that the Commission cannot order TVA to transmit power for any entity if that power will be consumed within the TVA service area. TVA argues that this transmission service over TVA's system is the foreseeable effect of ordering the interconnection, and that *El Paso Electric Co. v. FERC*[15] has established that the Commission must consider all foreseeable consequences, not just the benefits, before issuing an interconnection order.

14. TVA makes several arguments as to why it believes the proposed interconnection involves transmission service, and not merely loop flow as EKPC has maintained. TVA claims that loop flow has been defined as inadvertent or unauthorized power flows that are an unavoidable consequence of interconnected utility operations that can occur sometimes.[16] According to TVA, EKPC's flows do not fit that definition because: (1) they are not inadvertent or unavoidable; (2) they will happen every day instead of being an occasional occurrence; and (3) the magnitude[17] of the flows will be significant.

15. TVA further argues that, even if the flows were inadvertent loop flows, such flow of power is still transmission service. TVA notes that the Commission has previously found that unauthorized loop flows constitute a service for which a transmission rate may

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[15] 201 F.3d 667 (5th Cir. 2000) (*El Paso*).

[16] *Citing American Electric Power Service Corp.*, 49 FERC ¶ 61,377 at 62,381 *reh'g denied*, 50 FERC ¶ 61,192 (1990) (*AEP I*) and *American Electric Power Service Corp.*, 93 FERC ¶ 61,151 at 61,474 (2000) (*AEP II*).

[17] According to TVA, if the Commission grants the interconnections, it will be ordering TVA to wheel power to EKPC, including up to 60 percent of Warren's power during normal conditions (including, it claims, 100 percent of the load at Franklin), and 100 percent of the Warren load when EKPC experiences single contingency facility outages and during scheduled outages. *See* TVA's May 31 Brief at 15.

be charged.[18] TVA acknowledges that compensation would ordinarily be the appropriate remedy, but argues that, because of section 212(j), TVA should not be forced to provide transmission service to EKPC in the first place.

16. TVA also argues that the interconnections requested are not truly interconnections. TVA argues that a true interconnection between transmission systems will allow for bi-directional flows between the systems, while in EKPC's case the requested interconnections will not be capable of bi-directional flows.

17. TVA maintains that, if the Commission orders the interconnections, it will deviate from existing Commission policy and federal law. TVA notes that section 210(c) requires that the Commission determine that certain types of efficiency, conservation, or reliability improvements are realized through the proposed interconnection before issuing an order directing interconnection. TVA points out that, absent transmission service being provided through the physical facility, an interconnection is of no real, legitimate benefit, and therefore fails to meet the standard set in section 210(c).

18. TVA further argues that, in order to meet the standard set in section 210(c), the Commission would have to do a much more thorough cost benefit analysis than the record in this case permits. TVA argues that costs incurred by TVA and its ratepayers outweigh any purported benefit of the proposed interconnection. TVA points out that EKPC's proposal will decrease TVA's transfer capability by over 700 MW initially and that this loss of capability will increase as Warren's load grows. TVA argues further that restrictions on the capability to transfer power between and among control areas would, it argues, impact regional reliability.

19. TVA argues that the Commission's interconnection policy recognizes that interconnection by itself conveys no right to delivery service.[19] TVA maintains that the Commission's decision to direct the interconnections in this case, in effect, reverses that policy by rebundling the physical interconnection with delivery service.

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[18] *Citing AEP II* and *Southern Company Services Inc.,* 60 FERC ¶ 61,273 at 61,928 (1992) (*Southern*).

[19] *Citing Tennessee Power Co.,* 90 FERC ¶ 61,238 at 61,761 (2000), *Laguna Irrigation District,* 95 FERC ¶ 61,305 at 62,038 (2001), *aff'd sub nom. Pacific Gas and Electric Co.*, 44 Fed. Appx. 170 (9^{th} Cir. 2002) (*Laguna*), and *City of Corona v. Southern California Edison Co.,* 104 FERC ¶ 61,085 at 61,306 (2003) (*Corona*).

20. TVA next argues that it cannot provide the coordination services requested by EKPC. TVA states that, if it were required to provide such voltage support and backup services, it would need to dedicate generating capacity and transmission facilities to the production of reactive power in order to satisfy this obligation to EKPC. According to TVA, the Commission can order TVA to provide such service under neither section 210, which applies only to interconnections, nor section 211, because of the limitations on the Commission's authority to order transmission service under section 212(j). TVA also argues that, if the Commission requires TVA to provide such support, it would violate TVA's obligations under a Consent Judgment in *Alabama Power Co. v. TVA*.[20]

21. In responding to EKPC's May 31 Brief, TVA argues that its Existing IA should not be amended as proposed by EKPC to add the new interconnection points, because such an amendment would materially change previously negotiated terms and conditions in the IA.[21] Additionally, TVA contends that the Commission lacks the authority to require amendment of an existing agreement between two non-jurisdictional utilities.

22. Finally, TVA requests the Commission either vacate the Proposed Order and issue a final order dismissing EKPC's application for interconnection or set the matter for an evidentiary hearing.

III. Discussion

A. TVA's Arguments Regarding the Proposed Order

23. As the Commission explained in the Proposed Order, section 210 requires that, in order for the Commission to order an interconnection, it must find that the interconnection is in the public interest and that the proposed interconnection will meet at least one of the three specified criteria, *i.e.*, it will encourage conservation of energy or capital, optimize efficiency of facilities and resources, or improve the reliability of any electric utility system to which the order applies. The Commission found in the Proposed Order that EKPC met these criteria for an order directing the interconnection and, accordingly, directed it. However, our decision directing the proposed interconnection in the Proposed Order was based solely on section 210 of the FPA. We were not and are

[20] Civil Action No. CV-97-C-0885-S (N.D. Ala.) (July 29, 1997) (Consent Judgment).

[21] In its brief, EKPC proposes amendments to an existing IA as well as modifications to the physical interconnections proposed in its initial Application.

not acting under section 211;[22] therefore TVA's arguments related to section 212(j) of the FPA, which expressly applies only to an "order issued under section 211," do not apply in this case.

24. TVA conflates interconnection (which we order under section 210) and transmission (which we can, in other circumstances, order under section 211). Congress clearly intended otherwise, and created separate sections to cover each. It limited the section 212(j) prohibition to section 211 transmission orders. It did not extend the section 212(j) prohibition to section 210 interconnection orders. Indeed, different categories of entities are subject to section 210 interconnection orders (electric utilities) and section 211 transmission orders (transmitting utilities). We note that some provisions of section 212 explicitly apply to only sections 210 or 211, while other portions apply to both. In addition to section 212(j), which only precludes the Commission from directing transmission by TVA to load within its territory, sections 212(a), 212(c)(2)(B), 212(h), and 212(k) refer only to section 211 or transmission.[23] Thus, we see no basis to adopt TVA's reading of section 212(j) and to extend the limitations on Commission authority beyond the expressly-stated "order issued under section 211." TVA also errs in claiming that our action here rebundles interconnection and delivery service. We recognize the distinction between interconnection and delivery, and will order only the former here.

25. We disagree with TVA's contention that a "true" interconnection must be capable of bi-directional flow. The *National Rural* case cited by TVA to support this contention dealt with the question of whether a unidirectional contract path should be sufficient to deem two areas as "interconnected" for purposes of merger review by the Securities and Exchange Commission under the Public Utility Holding Company Act of 1935, not whether the contract path itself should be considered an interconnection under section 210 of the FPA.

26. We also disagree with TVA's interpretation of *AEP II* as supporting the argument that a power flow must necessarily be intermittent in order to be considered loop flow. Rather, when *AEP II* uses the word "sometimes," it refers to the fact that loop flow is a

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[22] With respect to the numerous TVA arguments concerning their claim that the interconnection required in the Proposed Order results in transmission, we note that, in accordance with *Laguna* and *Corona*, cited by TVA, we are not directing TVA to provide EKPC with transmission in this case, but merely to provide interconnection.

[23] Indeed, in *Laguna*, the Ninth Circuit affirmed the Commission's finding that section 212(h) applies only to transmission orders under section 211, but not to interconnection orders under section 210.

problem that we "sometimes" encounter, not that loop flow is necessarily intermittent in nature. Some instances of loop flow are intermittent (for example, loop flow associated with intermittent transactions); however, other types of loop flow are ongoing. We note that there is loop flow associated with all interconnections between systems, a product of today's integrated electric grid.[24]

27. Moreover, inadvertent loop flows are not unique to the TVA system, and TVA is not without recourse to address this issue. The Commission's policy on unauthorized power flows is clear. For example, in *AEP I*, the Commission denied a request for a technical conference stating:

> Inadvertent or unauthorized power flows are an unavoidable consequence of interconnected utility operations. Interconnected utilities must, and do, work closely to ensure that the operation of one system does not jeopardize the reliability of a neighboring system, nor diminish the neighbor's ability to utilize its system in the most economical manner. This coordination is accomplished by direct day-to-day communications and the establishment of operating committees, as well as the participation in power pools.... It is

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[24] In this regard, we note that TVA's arguments regarding inadvertent power flows associated with the EKPC interconnection are analogous to the inadvertent power flows associated with the "contract path" transmission pricing method used in the electric industry. A contract path is simply a path that can be designated to form a single continuous electrical path between the parties to an agreement. Because of the laws of physics, it is unlikely that the actual power flow will follow that contract path. In Order No. 888, the Commission recognized that there may be difficulties in using a traditional contract path approach in a non-discriminatory open access transmission environment. At the same time, however, the Commission noted that contract path pricing and contracting is the longstanding approach used in the electric industry and it is the approach familiar to all participants in the industry. *See Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities and Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,668 (1996), *order on reh'g*, Order No. 888-A, FERC Stats. & Regs. 31,048 (1997), *order on reh'g*, Order No. 888-B, 81 FERC 61,248 (1997), *order on reh'g*, Order No. 888-C, 82 FERC 61,046 (1998), *aff'd in relevant part*, *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).

> in the first instance, for the interconnected parties as the owners and operators of utility systems to establish mutually acceptable operating practices.[25]

28. In *Southern*, the Commission quoted its loop flow policy from *AEP I* and went on to state: "TVA is not a jurisdictional public utility and cannot take advantage of the second option, *i.e.*, cannot file with the Commission a transmission rate for unauthorized flows" should negotiations with the affected parties in that case "not produce an agreeable result."[26] The Commission also noted that "TVA does have the ability to seek compensation" from the affected parties in that case, "using whatever other recourse may be available to it (such as seeking compensation in a court of competent jurisdiction)" should negotiations fail.[27] However, we have re-evaluated our past determinations in light of the facts presented and have determined that, should TVA be unable to negotiate compensation with EKPC, we can and should allow TVA the opportunity to seek compensation, through the section 210 IA being ordered below, for loop flow it incurs as a result of EKPC's proposed interconnection. Because TVA as a non public utility cannot file a transmission rate at the Commission for unauthorized flows (which would be the normal vehicle for a public utility to seek cost recovery), and because the costs of such flows will occur as a result of a Commission-ordered interconnection, we believe cost recovery should be permitted through the IA rather than TVA having to go to another forum to seek recovery.

29. Regarding TVA's arguments about coordination services, we note that section 210(a)(1)(C) expressly provides that the Commission may issue an order requiring "such sale or exchange of electric energy or other coordination, as may be necessary" to carry out a directed interconnection. Moreover, FPA section 212(j) does not restrict our authority to require TVA to provide these services, since section 212(j) limits our authority only under section 211. TVA may seek to recover any costs associated with these coordination services in the interconnection agreement we are directing it to file, below.

30. Regarding TVA's argument concerning the requirement of *El Paso* to consider foreseeable consequences, we recognize that inadvertent loop flow may be a consequence from the interconnection we are ordering here. However, we are not ignoring the

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[25] *AEP I,* 49 FERC at 62,381.

[26] 60 FERC at 61,928.

[27] *Id.*

reliability concerns TVA has raised. In the Proposed Order, we directed the parties to ensure that "any agreement that may be reached with respect to interconnection must adequately maintain the reliability of the system."[28] After we receive the revised System Impact Studies we are directing below (where we expect all reliability issues to be addressed), we will, of course, evaluate the proposed interconnections to ensure that reliability is not impaired.

31. Finally, we disagree with TVA that the settlement in the Consent Judgment limits our ability to act under section 210. The focal point of the litigation and the Consent Judgment is to ensure that TVA does not sell power inappropriately outside the "fence;" here, the supply of power is for Warren, inside the fence. More importantly, parties to a settlement of litigation in which the Commission is not participating cannot limit the authorities given to us by Congress (except by waiving their own rights to invoke those powers). We must respect limits imposed by Congress. Other entities cannot, as parties to a settlement in which we have no role, further restrict our powers provided by Congress.

32. For the reasons discussed above, we affirm our conclusion in the Proposed Order, and reject TVA's arguments to the contrary.

B. System Impact Studies

33. In its May 31 Brief, EKPC notes that it made four modifications to the proposed physical interconnections first outlined in its Application, including: (1) lengthening the line of the Barren County-Magna 161 kV line to more accurately reflect the siting of that line; (2) including a 161 kV power circuit breaker between two Warren-owned transformers at the East Bowling Green Substation; (3) constructing additional facilities at the Memphis Junction Substation to provide it with two sources of power independent of TVA in the Memphis Junction area; and (4) relocating the interconnection originally proposed at Franklin Substation to Salmons. EKPC notes that, in addition to these four modifications, it plans to make additional modifications to the Warren 69 kV distribution system and the Barren County-Magna 161 kV line to reflect further engineering considerations associated with the upgrade of certain Warren distribution facilities and siting issues. We continue to believe that this interconnection would encourage the conservation of energy and capital and benefit native load customers, by providing Warren with access to more economical sources of power and that, as the result of this interconnection, Warren and its customers would be able to purchase power at lower rates than they pay TVA.

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[28] *See* Proposed Order at P 38.

34. TVA challenges the physical interconnection modifications arguing that EKPC apparently viewed the Proposed Order as authorizing three interconnections, the location of which could be determined at will without proper study and review. TVA notes that the three interconnections requested in EKPC's Application are not the same points of interconnection identified by EKPC in the Proposed Amendments. TVA points out that EKPC dropped its request for an interconnection point at Franklin and substituted a new interconnection point at Salmons. According to TVA, the impact of this change is unknown because neither TVA nor Commission Staff have studied the effect of this new interconnection point. TVA points out that the Commission did not include the Salmons interconnection point in the Proposed Order. TVA proposes that, if the Commission directs the interconnection, discovery and an evidentiary hearing are warranted in order to determine whether the Proposed Amendments or a new agreement should be used for EKPC's interconnections and, if so, the terms and conditions that should be included in either agreement.

35. The Commission finds that EKPC did not include data in its May 31 Brief to support its contention that its modifications of the physical interconnections in the initial Application will not change the System Impact Study findings. EKPC's modifications make it difficult to rely on the System Impact Studies submitted as part of the filings made at the time of EKPC's initial Application, as supplemented by the parties' responses to Commission's data request. As TVA recognizes, the Commission is unable, at this time, to evaluate the impact of these modifications to EKPC's initial Application on the System Impact Studies that served as the basis of the Commission's Proposed Order. Therefore, the Commission directs EKPC to file its modified System Impact Study reflecting the modifications of the physical interconnections in its initial Application, as well as any other modifications not specifically identified, with the Commission, and to serve it on TVA, within fifteen (15) days of the date of issuance of this order. The Commission directs TVA to file a modified System Impact Study, including the relevant Critical Energy Infrastructure Information (CEII) information, with the Commission and to serve it on EKPC, within 30 days of EKPC's filing. EKPC will then have fifteen (15) days from the date of TVA filing the modified System Impact Study to submit a response to TVA's modified study.

36. TVA has raised several arguments claiming that issues of fact remain that should be addressed in a hearing. We find that a hearing is premature at this stage of the proceeding in light of the fact that we are ordering the submission of revised System Impact Studies, as described above. Absent such information, we cannot evaluate whether there are material facts in dispute warranting an evidentiary hearing.

C. Submission of Proposed Interconnection Agreement

37. The Commission rejects EKPC's submission of a modified existing IA to establish the rates, terms and conditions for the interconnections in its May 31 Brief. EKPC's use of the Existing IA in this case is inappropriate. We note, further, that TVA did not include any documentation regarding the rates, terms and conditions in its May 31 Brief. TVA appears to have misunderstood our direction, in the Proposed Order, that it file its "final position . . . accompanied by any necessary supporting data"[29] on the appropriate rates, terms, and conditions for interconnection. Consequently, we cannot now determine the appropriate rates, terms, and conditions under which interconnection should be effectuated.

38. Accordingly, we direct TVA to file an Interconnection Agreement containing the rates, terms, and conditions under which it will interconnect with EKPC's system, as well as provide coordination services necessary for EKPC to deliver energy to Warren, within 30 days of the date of this order. EKPC will then have 15 days to respond to that filing. As with the System Impact Study, a Commission determination on whether there should be a hearing on rates, terms and conditions is premature until TVA files an Interconnection Agreement with its proposed rates, terms and conditions, and EKPC responds.

39. Pursuant to section 212(c)(1), this order shall not be reviewable or enforceable in any court. In addition, we clarify that, consistent with Rule 713 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.713 (2005), this is an interlocutory order not subject to requests for rehearing. The proper time for the parties to seek rehearing is after the Commission issues a final order under section 210.[30]

<u>The Commission orders</u>:

(A) TVA is hereby directed to file an Interconnection Agreement containing rates, terms, and conditions for interconnection with EKPC, as discussed in the body of this order, within 30 days of the date of issuance of this order, with EKPC's response due within 15 days of the date of TVA's filing.

---

[29] Proposed Order at P 44.

[30] *Florida Municipal Power Agency v. Florida Power & Light Co.*, 65 FERC ¶ 61,372 at 63,013 (1993).

(B) EKPC is hereby directed to file with the Commission and serve on TVA a revised System Impact Study reflecting all of its modifications to its initial Application, as discussed in the body of this order, within fifteen (15) days of the date of issuance of this order.

(C) TVA is hereby directed to file its revised System Impact Study with the Commission and to serve it on EKPC, as discussed in the body of this order, within 30 days of EKPC's filing, as provided in Ordering Paragraph (B).

By the Commission.

(S E A L)

Linda Mitry,
Deputy Secretary.

EXHIBIT 1-2

Big Rivers
Electric Corporation

201 Third Street
P.O. Box 24
Henderson, KY 42419-0024
270-827-2561
www.bigrivers.com

April 18, 2005

Mr. Paul C. Atchison
Vice President Power Delivery
East Kentucky Power Cooperative
4775 Lexington Road
P.O. Box 707
Winchester, Kentucky 40392-0707

RE: Wilson-Aberdeen 161 kV Line

Dear Paul:

In response to your letter dated March 14, 2005, Big Rivers anticipates no adverse system impacts would result from a Wilson to Aberdeen 161 kV interconnection as proposed by East Kentucky Power Cooperative. Consequently; Big Rivers does not object to this tie. Big Rivers Power Supply indicates that there has been no transaction developed between them and the East Kentucky Power counter parts that would place a value on this tie from Big Rivers' point of view.

As discussed by phone on April 13, 2005, Big Rivers will begin the process of preparing an interconnection agreement. It is anticipated that facility ownership, project funding, and transmission service charges/transmission credits that may result from the network upgrade will all be addressed in this agreement.

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

Sincerely,

BIG RIVERS ELECTRIC CORPORATION

Travis D. Housley
Vice President, System Operations

C: David Spainhoward
Chris Bradley

EAST KENTUCKY POWER COOPERATIVE, INC.

PSC CASE NO. 2005-00207

INFORMATION REQUEST RESPONSE

COMMISSION'S FIRST DATA REQUEST DATED 8/18/05

ITEM 2

RESPONSIBLE PARTY: DAVID SHAFER

REQUEST: Provide a list of changes and updates that East Kentucky Power made to the East Central Area Reliability Coordination Agreement 2003 series of the 2010 Summer cases in order to perform its own studies.

RESPONSE: The base case for the study was the ECAR 2003 series 2010 Summer case. EKPC includes all of its transmission system and load buses in the ECAR model. Therefore, no changes were made to the EKPC system other than those documented in the CAI report and those listed below.

1. The BREC detailed transmission model was inserted in place of the simplified BREC model. Also, the BREC generation dispatch was modified to dispatch all steam units at maximum output, with the resulting surplus generation exported to the south.

2. A detailed WRECC model was added to the case. Also, this system was added into the EKPC control area and the interchange was adjusted to model generator services via TVA in Case A and EKPC in all other cases. Refer to the CAI January 27, 2005, study report Table 2 for a list of WRECC load buses and loads. Refer to Exhibit 3 of that report for a diagram of the WRECC transmission system.

3. The study variations between Cases A, B, C and D are documented in the study report as follows:

a. Changes to loads and losses (Table 6)

b. Changes to area interchange (Table 7)

c. Changes to generation dispatch (Table 8)

4. The transmission line additions for each study Plan are described in CAI's January 27, 2005 report.

EAST KENTUCKY POWER COOPERATIVE, INC.

PSC CASE NO. 2005-00207

INFORMATION REQUEST RESPONSE

COMMISSION'S FIRST DATA REQUEST DATED 8/18/05

ITEM 3

RESPONSIBLE PARTY: MARY JANE WARNER

REQUEST: Provide a comparison of the contingencies used in the Commonwealth Associates, Inc. ("CAI") study and those considered by MISO in its studies.

RESPONSE: The MISO's independent analysis of EKPC's Project compared the contingency analysis results of the MISO Baseline Reliability 2009 Summer Peak case with and without the EKPC Project. Therefore, the entire contingency list utilized by MISO's Expansion Planning Group in its Baseline Reliability study was tested by MISO for the review of the EKPC Project. This is a much more expansive list than that used in the CAI study. The contingency list used by CAI consists primarily of transmission facilities in south-central and western Kentucky, central and western Tennessee, and southwestern Indiana. This is the area of interest in this study.

Information is not readily available to perform a specific comparison to determine if the MISO analysis of the EKPC Project considered all of the contingencies used by CAI.

It is reasonable to conclude that although the sets of contingencies used in the CAI study versus the MISO study were not exactly the same, CAI did a study that thoroughly assessed the area encompassed by the proposed EKPC Project. Similarly, MISO performed a thorough assessment of the impacts of the EKPC Project on a wider regional level. The results of both studies indicate that the proposed Project performs adequately on a local and regional level.

EAST KENTUCKY POWER COOPERATIVE, INC.

PSC CASE NO. 2005-00207

INFORMATION REQUEST RESPONSE

COMMISSION'S FIRST DATA REQUEST DATED 8/18/05

ITEM 4

RESPONSIBLE PARTY: PAUL ATCHISON

REQUEST: What are the wheeling costs for the Warren Rural Electric Cooperative Corporation ("WRECC") load served over the LGEE lines and any other operating costs associated with East Kentucky Power's proposed line?

RESPONSE: In 2008, the forecasted peak demand for the WRECC loads to be served via the LGEE transmission system is 59.8 MW. Using an estimated MISO/LGEE transmission rate for network service of $1.21 per kW-month and a diversity factor of 0.75, the first-year cost of transmission wheeling for these loads is calculated to be $651,222.

In Paragraph 15 of the Application for a Certificate filed for the EKPC Project, a first-year cost of operation of $3,053,812 was provided. This cost did not include the cost of transmission wheeling that would be incurred by EKPC, and also did not include all components of the EKPC Plan for service to Warren. The Response to Item #9 lists all components of the EKPC Plan and the total cost. Based on that total cost and the first-year transmission wheeling charges calculated above, the first-year cost of operation becomes $4,871,819.

EAST KENTUCKY POWER COOPERATIVE, INC.

PSC CASE NO. 2005-00207

INFORMATION REQUEST RESPONSE

COMMISSION'S FIRST DATA REQUEST DATED 8/18/05

ITEM 5

RESPONSIBLE PARTY: DAVID G. EAMES

REQUEST: Provide East Kentucky Power's generation expansion plan for serving its load, including WRECC, through 2010.

RESPONSE: The following is EKPC's planned generation expansion plan for the 2005 through 2010 period:

Table 5-1
EKPC Planned Generation Additions for 2005-2010

Date	Unit Added	Net Capacity Added	
		Summer	Winter
April 2007	JK Smith CT #8	83 MW	97 MW
November 2007	JK Smith CT #9	83 MW	97 MW
November 2007	JK Smith CT #10	83 MW	97 MW
April 2008	Spurlock #4 (CFB)	278 MW	278 MW
April 2008	JK Smith CT #11	83 MW	97 MW
April 2008	JK Smith CT #12	83 MW	97 MW
April 2009	JK Smith #1 (CFB)	278 MW	278 MW

EAST KENTUCKY POWER COOPERATIVE, INC.

PSC CASE NO. 2005-00207

INFORMATION REQUEST RESPONSE

COMMISSION'S FIRST DATA REQUEST DATED 8/18/05

ITEM 6

RESPONSIBLE PARTY: MARY JANE WARNER

REQUEST: Provide the design and reliability criteria used for East Kentucky Power's transmission system power flow studies.

RESPONSE: The design objective of the EKPC transmission study for service to WRECC was to develop a transmission system that satisfied the following requirements:

- provide a direct connection from the EKPC system to the Warren system, with sufficient capacity between the two systems
- satisfy EKPC Transmission System Planning Guidelines
- not adversely impact neighboring systems
- provide an economically competitive solution
- consider long-term requirements in the area and provides the ability to add additional facilities when required by area load growth
- accommodate routine operation and maintenance

The planning horizon for this study is 2008 to 2010 to reflect expected system conditions at the time the WRECC load is served via EKPC.

Transmission planning assessment is accomplished through power flow studies using ECAR developed, seasonal power system models with a more detailed model of the Kentucky transmission system in the vicinity of the study area.

Criteria

I. Contingencies

For the purpose of determining minimum transmission system requirements, the following contingency events are tested:

A. Normal System (no contingencies)

1. Peak Demand with all transmission facilities in service (for the WRECC System: Summer Peak Demand)

B. Single Contingency

1. Sudden outage of any transmission circuit, transformer or generator at peak system demand.

2. Sudden outage of any transmission circuit, or transformer while the transmission system is reconfigured for a generator out of service.

II. Performance

Acceptable operating performance for the above conditions is as follows:

A. For Normal System

System voltages: 94 to 105%

Facility Loadings: within normal seasonal ratings

B. For Single Contingencies

System voltages: 90 to 105%

Facility Loadings: within emergency seasonal ratings

After a sudden outage; however, before any operator directed system adjustments are made, all facility loadings are to be within seasonal emergency ratings and all bus voltages are to be within 90% to 105%. Any loss of load is restored through routine operator directed switching procedures.

III. Transmission Circuit Ratings

Overall loading criteria for transmission lines are initially based on conservative conductor and line terminal equipment ratings. Lines are rated at the lower of the conductor or terminal equipment rating (see the attached Exhibit 6-2).

V. Generation Limits

Generators are operated within their seasonal maximum net MW and maximum net MVAR limits.

VI. Voltage Limits

System voltages are kept within the normal limit of 94% to 105% and the emergency limit of 90% to 105%.

Reliability Assessment

EKPC participates as a member of ECAR and adheres to reliability standards as established by ECAR and NERC.

Supporting Documents

Exhibit 6-1 is EKPC's "Transmission System Planning Criteria" Document.

Exhibit 6-2 is EKPC's "Methodology for Determining Transmission Facility Ratings" Document.

Exhibit 6-1

East Kentucky Power Cooperative
(EKPC)

Transmission System Planning Criteria

May 9, 2001

Section 1
Overview and General Discussion

The primary purpose of East Kentucky Power Cooperative's (EKPC's) transmission system is to reliably transmit electrical energy from its available generating resources to customers served by its transmission system. Interconnections have been constructed in the past with other utilities, to increase the reliability of the EKPC transmission system, and to provide EKPC customers access to other economic and/or emergency generating resources.

EKPC subscribes to and designs its transmission to conform to the fundamental characteristics of a reliable interconnected bulk electric system recommended by the North American Electric Reliability Council (NERC). Additionally, EKPC is a member of the East Central Area Reliability Coordination Agreement (ECAR) and subscribes to and designs its transmission system to comply with the reliability principles and responsibilities set forth in ECAR Documents.

The Federal Energy Regulatory Commission (FERC) requires all public utilities that own, operate, or control facilities used for transmitting electric energy in interstate commerce to have on file open access non-discriminatory transmission tariffs. EKPC has these tariffs on file to provide firm and non-firm point-to-point transmission service for other entities, as well as firm network service.

The American National Standards Institute (ANSI), The Institute of Electrical and Electronic Engineers, Inc (IEEE), and The Rural Utilities Services (RUS) all publish standards for power system equipment design and application. EKPC incorporates these standards in the design and application of equipment utilized on its transmission system.

The NERC and ECAR standards previously referred to above are discussed in Section 2. The EKPC Planning Criteria is presented in Section 3.

Section 2
NERC and ECAR Planning Standards

NERC in its planning standards report states the fundamental requirements for planning reliable interconnected bulk electric systems and the required actions or system performance necessary to comply. The Regions, sub regions, power pools, and their members have the responsibility to develop their own appropriate planning criteria and/or guides that are based on the NERC Planning Standards.

EKPC is a member of ECAR. ECAR has developed Document 1 entitled, "Reliability Criteria for Evaluation and Simulated Testing of the Bulk Systems", in compliance with the NERC Planning Standards report. ECAR Document 1 contains the standards that transmission providers are expected to adhere to in their simulated testing and system performance evaluations. EKPC has developed and adopted planning criteria and guides that meet or exceed ECAR Document 1 standards and requirements.

Section 3
EKPC Transmission System Planning Criteria

3.1 Overview

In general, EKPC's transmission system is planned to withstand forced outages of generators and transmission facilities, individually and combined. Table 1 describes the contingencies and measurements EKPC utilizes in testing and assessing the performance of its transmission system

For all testing conditions, stability of the network should be maintained, and cascading outages should not occur. Specific modeling considerations are considered as part of the testing conditions, which are discussed in Section 3.1.

Table 1: Transmission Planning Contingencies and Measurements

Contingencies[1]	Max. Facility Ratings	Min. Volt Level (P.U.)[2]	Max. Volt Level[3] (P.U.)	Curtail Demand and/or Transfers
None(Base Case)	Tables 2,3	0.955	1.050	no
Extreme load due to unusual weather.[4]	Tables 2,3	0.940	1.050	no
Outage of a generator, transmission circuit, or transformer.[5]	Tables 2,3	0.925	1.050	no
Outage of two(2) generators.	Tables 2.3	0.925	1.050	no
Outage of a generator and a transmission circuit or transformer.	Tables 2,3	0.925	1.050	no
Outage of a bus section or a circuit breaker.[6]	Tables 2,3	0.925	1.050	yes
Outage of two(2) transmission circuits.	Tables 2,3	0.925	1.050	yes
Outage of a transmission circuit and a transformer.	Tables 2,3	0.925	1.050	yes
Outage of two(2) transformers.	Tables 2,3	0.925	1.050	yes
Outage of a double circuit tower line.[7]	Tables 2,3	0.925	1.050	yes
Outage of a generator, transmission circuit, transformer, or bus section.[8]	Tables 2,3	0.925	1.050	yes

---

[1] All contingencies(except as noted) are single line to ground or 3-phase faults with normal clearing. For all testing conditions, network stability should be maintained and cascading should not occur.

[2] Measured at the unregulated low side distribution transformer bus.

[3] For peak load conditions. Maximum off-peak voltage level at unregulated low side distribution transformer bus = 1.085 P.U.

[4] Based on a 10% probability load forecast. Fault conditions do not apply.

[5] Includes outages which do not result from a fault.

[6] Single line to ground with normal clearing.

[7] Non 3-phase, with normal clearing.

[8] Single line to ground, with delayed clearing.

Table 2: EKPC Typical Line Ratings[9]
(Maximum Conductor Operating Temperatures)

Line Type	Thermal Capability(MVA) Normal / Contingency[10] 176 / 212°F Operation Winter	Summer
69 kV 1/0 ACSR6x1	37 / 40	27 / 32
69 kV 2/0 ACSR 6x1	43 / 46	31 / 37
69 kV 3/0 ACSR 6x1	54 / 59	39 / 47
69 kV 195.7 ACAR	58 / 64	42 / 51
69 kV 4/0 ACSR 6x1	62 / 68	45 / 55
69 kV 266.8 ACSR 26x7	78 / 87	57 / 69
69 kV 556.5 ACSR TW 26x7	121 / 135	88 / 108
69 kV 556.5 ACSR 26x7	125 / 139	90 / 111
69 kV 795 ACSR 26x7	157 / 175	113 / 140
138 kV 556.5 ACSR TW 26x7	242 / 270	176 / 216
138 kV 556.5 ACSR 26x7	250 / 278	181 / 222
138 kV 636 ACSR 26x7	273 / 303	197 / 242
138 kV 795 ACSR 26x7	315 / 351	227 / 280
138 kV 954 ACSR 54x7	349 / 389	251 / 311
161 kV 636 ACSR 26x7	318 / 354	230 / 283
161 kV 795 ACSR 26x7	367 / 409	265 / 327
161 kV 954 ACSR 54x7	407 / 454	293 / 363
345 kV 2-954 ACSR 54x7	1746 / 1947	1257 / 1554

[9] Line rating may be limited by terminal facilities or by maximum existing conductor operating temperature.

[10] Normal ratings apply only to base case conditions. Contingency ratings apply to contingency conditions.

Table 3: EKPC Transformer Ratings(Maximum)[11]

	Rated kV			MVA Rating[12]			
	High Side	Low Side	Rated MVA	Summer(95F) Norm	Summer(95F) Emer	Winter(32F) Norm	Winter(32F) Emer
55C Rise							
OA	161	138	75	71	107	100	135
	161, 138	69	75	71	107	100	135
	161	69	60	57	86	80	108
	161, 138	69	50	47	71	67	90
	138	69	49.5	47	71	66	89
	138	69	45	43	64	60	81
	161	69	35	33	50	47	63
	161	69	26.8	25	38	36	48
	138	69	25.5	24	36	34	46
OA/FA/FA							
OA/FOA/FOA	138	69	82.5	78	111	107	136
65C Rise							
OA	345	138	270	257	367	340	475
	345	138	180	171	245	227	317
	161	138	90	86	122	113	158
	161, 138	69	90	86	122	113	158
	161, 138	69	60	57	82	76	106
OA/FA/FA	345	138	450	434	581	536	662
OA/FOA/FOA	345	138	300	290	387	357	441
	161	138	150	145	194	179	221
	161, 138	69	150	145	194	179	221
	161	138	140	135	181	167	206
	161, 138	69	140	135	181	167	206
	161, 138	69	100	97	129	119	147
	161, 138	69	93.3	90	120	111	137
	138	69	84	81	108	100	123
	161, 138	69	65.4	63	84	78	96
	138	69	65.3	63	84	77	96
	161	69	50	48	65	60	74
	138	69	47.6	46	61	57	70

3.1 Plant Voltage Schedules

[11] Transformer rating may be limited by terminal facilities.

[12] Normal ratings apply only to base case conditions. Contingency ratings apply to contingency conditions.

For major power plants, the voltage level at the high side of the generator step up transformer(GSU) should be maintainable with normal generation and normal transmission system conditions as follows:

Plant Name	GSU High Side Bus Name and (kV)	Scheduled Voltage (kV)	Scheduled Voltage (Per Unit)
H. L. Spurlock	Spurlock 345	355	1.029
H. L. Spurlock	Spurlock 138	142	1.029
J. S. Cooper	Cooper 161	166	1.031
W. C. Dale	Dale 138	142	1.029
W. C. Dale	Dale 69	72	1.043
J. K. Smith	J. K. Smith 138	142	1.029

3.2 Modeling Considerations

Replacement generation required to offset generating unit outages should be simulated first from all available internal resources. If internal resources are not available or are exhausted, then replacement generation should be simulated from the most restrictive of interconnected companies (AEP, CINergy, LGEE, or TVA).

A single outage may include multiple transmission components in the common zone of relay protection.

Post-fault conditions and conditions after load restoration should be evaluated. Post-contingency operator initiated actions to restore load service must be simulated. Load that is off-line as a result of the contingency being evaluated may be switched to alternate sources during the restoration process, however, load should not be taken off-line to perform switching.

Transmission capacitor status (on/off) should be simulated consistent with existing automatic voltage control (on/off) settings and operating practice during normal transmission system conditions. Manual on-line switching of capacitors during normal conditions can be simulated provided it is consistent with existing operational practice, however, manual switching should not be simulated following a contingency to eliminate low voltage conditions.

The following operational procedures should be avoided:

1) Seasonal adjustment(s) of fixed taps on transmission transformers to control voltage(s) within acceptable ranges.

2) Switching HV and EHV system facilities out of service to reduce off-peak voltage(s).

3.3 Reliability Criteria

Customer Interruptions - Customer interruptions may occur due to an outage of a subtransmission circuit or a distribution substation transformer. To minimize the time and number of customers affected by a single contingency outage, the following criteria should be applied:

(a) Spare Distribution Transformer - To provide for the failure of the distribution substation transformer, a spare transformer should be maintained and available for installation at the affected substation within 10 hours.

(b) Distribution Substation Supply - Transmission radial supply to a distribution substation is acceptable provided that the tap "load-exposure" index, TE, does not exceed 100 MW-miles. When this index is exceeded, multiple source supply should be provided to reduce this index below 100 MW-miles.

(c) Subtransmission Circuit - The circuit "load-exposure" index, CE, should not exceed 2400 MW-miles.

3.4 Load Level

Future transmission facility requirements should be determined using power flow base cases which model coincident individual substation peak demands(summer and winter) forecasted on a normal weather basis. Future transmission facility requirements should also be determined using summer and winter load flow base cases simulating a 10% probability severe weather load forecast. A severe weather load flow case will be considered in itself as an abnormal system planning condition.

Exhibit 6-2

East Kentucky Power Cooperative

Methodology for Determining Transmission Facility Ratings

A. Transmission Circuit

The current carrying capacity of each transmission circuit is determined by the minimum continuous current carrying capability of all series connected facilities on that line. Facilities that are considered include the thermal rating of the conductor, circuit breakers, bushings, current transformers, bus, disconnect switches, wave traps, and relaying. The determination for the current carrying capability of each of these facilities is discussed below.

1. Conductor Thermal Rating

i) Methodology

(1) The ECAR Conductor Thermal Rating Program (68-TAP-28) is used by EKPC. This program is based on modification of the "House and Tuttle" methodology that is used for determining continuous current carrying capability of transmission line conductors. This method was published in AIEE Transaction, Power Apparatus Section, February 1959, Volume 40, page 1169, entitled "Current Carrying Capability of ACSR". It is also available in the ALCOA Conductor Engineering Handbook, Section 6.

ii) Key Assumptions

(1) All of the key assumptions used in the equations for determining the Conductor Thermal Ratings are given below:

(1) Emissivity Coefficient	0.8
(2) Solar Absorption Coefficient	0.8

(3) Ambient temperature (degrees C)

(a) Summer	35
(b) Winter	0
(4) Wind /Conductor angle (degrees)	90
(5) Wind Velocity (mph)	2
(6) Conductor Max. Temp. (degrees C)	
(a) Normal (continuous rating)	80 *
(b) Emergency (24 hr limit) max. line	
(c) design temp(generally100)	

* The maximum design temperature for the line is used if below the 80 degree C (normal rating).

(7) All solar heating is considered regardless of time of day or sky conditions.

iii) Justification

(1) The methodology is recognized throughout the industry. The ECAR, AIEE, and Alcoa sources listed above (Paragraph 1) were used to provide a guide for selecting the program inputs based on EKPC's system characteristics. The emissivity and solar absorption coefficients are reasonable values for aged conductors. Ambient conditions are reasonable and prudent values based on climate, statistical analysis, and experience in the EKPC geographic area.

2. Circuit Breakers

i) Circuit breakers will be operated within the manufacturer's nameplate rating of the equipment for both continuous and emergency ratings. In cases where a bushing or current transformer would limit the nameplate rating, the rating of the circuit breaker will be determined by the limiting component.

ii) A methodology for rating of CTs is outlined in the Westinghouse "Memorandum On Thermal Characteristics of Current Transformers Used with Circuit Breakers" dated 6/26/69: *R.F.*= $\sqrt{I_b/I_{ct}}$, *where* I_b *is breaker nameplate rating,* I_{ct} *is CT primary rating on the tap used.* This factor is multiplied by the normal rating factor of the CT. The maximum rating factor must not exceed 2.0.

3. Bushings

i) Bushings will be operated within the manufacturer's nameplate rating of the bushing for both continuous and emergency ratings.

4. Current Transformers

i) Current transformers will be operated within the manufacturer's nameplate rating of the current transformer for both continuous and emergency ratings.

5. Bus

i) Typically, the rating of the bus is determined using same methodology as that used to determine conductor rating. In most cases the bus is designed so as to not limit the transmission line rating. In instances where the bus is the limiting factor, the rating of the transmission line will be determined by the bus rating.

6. Disconnect Switches

i) Disconnect switches will be operated within ratings determined by multiplying the manufacturer's nameplate rating and the following factors for both continuous and emergency ratings:

(1) The summer normal rating is obtained by multiplying the nameplate rating by 1.05.

(2) The summer emergency rating is obtained by multiplying the nameplate rating by 1.20.

(3) The winter normal rating is obtained by multiplying the nameplate rating by 1.25.

(4) The winter emergency rating is obtained by multiplying the nameplate rating by 1.30.

The factors specified above are values conservatively developed based upon IEEE Std C37.37.

7. Wave Traps

i) Wave traps will be operated within the manufacturer's nameplate rating of the wave trap for both continuous and emergency ratings.

8. Protective Relaying

i) Typically, relay settings will be applied so as not to limit the loadability of the conductor on a circuit. However, in some cases the relay settings may need to limit the conductor rating in order to provide adequate protection for the circuit. In such cases, the rating of the transmission line will be determined by this limiting factor.

(1) In cases where the relay loadability at maximum torque is inadequate, the relay will be rated at 90% power factor if load flow studies confirm this is appropriate. The relay rating at 90% power factor is then derated by 10% to account for relay circuit tolerances.

9. Series Reactors

i) Series reactors will be operated within the manufacturer's nameplate rating of the equipment for both continuous and emergency ratings.

B. HV Power Transformers

1. Transmission class HV power transformers have nominal and emergency ratings for summer and winter. The nominal rating may be applied continuously and the emergency rating for 4 hours. Summer ambient ratings are in effect from June 1 through October 31. Winter ambient/ratings are in effect from November 1 through May 30.

i) 65° C Rise

(1) The continuous current carrying capabilities of HV power transformers is determined by an adaptation of the methodology contained in NEMA PUB. NO. TR 98-1964 which is called "Standards Publication Guide for Loading Oil-Immersed Power Transformers with 65 C Average Winding Rise" for OA or OW and OA/FOA/FOA transformers.

(2) In multiplying the nameplate rating by 90% of the continuous equivalent load of 24 hours rated KVA preceding peak load in the Table 2-2, Part 2, Page 4 of PUB. NO. 98, the normal ratings of the transformer would be obtained. The nominal limit for all EKPC transformers is the maximum hot spot temperature.

(3) The emergency ratings are based on a peak load time of 4 hours or less and a loss of life of 1.0% or less for each emergency operation, which is shown in Table 3-6 of PUB. NO. TR 98, Part 3, Page 7. Emergency rating assumed the transformer was operating within nominal limits prior to the emergency operation.

(4) Therefore, based on ambient temperatures of 35°C for summer and 0°C for winter, the multipliers used to develop ratings for EKPC power transformers are:

For OA transformers

Summer Normal = 95% of nameplate
Summer Emergency = 136% of nameplate
Winter Normal = 126% of nameplate
Winter Emergency = 176% of nameplate

For OA/FOA/FOA transformers

Summer Normal = 96.5% of nameplate
Summer Emergency = 129% of nameplate
Winter Normal = 119% of nameplate
Winter Emergency = 147% of nameplate

ii) 55° C Rise

(1) The methodology (tables) contained in the USAS Appendix: C57.92, called "Standard Institute Guide for Loading Oil-Immersed Distribution and Power Transformers" was published in June 1962.

(2) In multiplying the nameplate rating by 90% of continuous equivalent load or rated KVA preceding peak load (Table 92-01.250A), the nominal ratings of the transformer would be obtained. The nominal ratings of the transformers are the maximum hot spot temperature.

(3) The emergency ratings are based on table 92.02.200P, Page 28, Capability Table for Forced-Oil-Cooled Transformers (FOA, FOW, or OA/FOA/FOA), and 4 hours or less and a loss of life of 1.0% or less for each emergency operation. Emergency rating assumes that the transformer was operating within nominal limits prior to the emergency operation.

(4) Therefore, based on ambient temperatures of 35°C for summer and 0°C for winter, the multipliers used to develop ratings for EKPC power transformers are:

For OA transformers

Summer Normal = 94.5% of nameplate
Summer Emergency = 142.5% of nameplate
Winter Normal = 133% of nameplate
Winter Emergency = 180% of nameplate

For OA/FOA/FOA transformers

Summer Normal = 94.5% of nameplate
Summer Emergency = 134.5% of nameplate
Winter Normal = 130% of nameplate
Winter Emergency = 165% of nameplate

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ITEM 7

RESPONSIBLE PARTY: DAVID SHAFER

REQUEST: Did East Kentucky Power consider double contingencies (n-2)? If yes, what were they and what conclusions did you make?

RESPONSE: Yes. Three critical 161 kV double circuit contingencies were identified by TVA in an email dated Friday, July 23, 2004, based on their independent studies using TVA's internal power flow model:

1. Wilson – Aberdeen 161 kV and East Bowling Green TVA-East Bowling Green EKPC 161 kV
2. Memphis Junction TVA-Memphis Junction EKPC 161 kV & Memphis Junction EKPC-BGMU Tap 161 kV
3. Memphis Junction TVA-Memphis Junction EKPC 161 kV and East Bowling Green TVA-East Bowling Green EKPC 161 kV

CAI investigated these double contingencies in the original EKPC-proposed plans and confirmed that they caused a significant loss of load in the proposed reconfiguration of the WRECC 69 kV system between Memphis Junction and Franklin, Kentucky. However, this loss did not cascade outside of this region and was, therefore, not a Category C (double contingency) violation of NERC criteria. Also noted, was a minor overload on the two in-series 161 kV circuits; Bowling Green 161 kV – S. Bowling Green 161 kV – Memphis Junction TVA 161 kV.

As a result of these and other related findings, EKPC made three changes to their implementation plans for service to WRECC. First, they added a new line from the former proposed BGMU Tap to Memphis Junction EKPC and reconfigured the three terminal circuit emanating from the previous BGMU Tap into two 161 kV circuits -- Aberdeen to Memphis Junction EKPC and Memphis Junction EKPC to General Motors. Second, they added a new 161 kV exit and 161 kV tie breaker at East Bowling Green EKPC and reconnected the General Motors – East Bowling Green EKPC 161 kV circuit into the new exit. Third, they added a 69 kV switching station at Plano to permit the sectionalizing of this 69 kV region for scenarios involving the loss of one of the three major substations serving the region.

As a result of these changes, local loss of all load in the 69 kV region between Memphis Junction and Franklin, Kentucky due to double contingencies as described above was eliminated. An additional benefit for this 69 kV region was that it could now survive the loss of any one of the three 69 kV secondary buses at the 161-69 kV substations servicing this 69 kV region of WRECC.

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ITEM 8

RESPONSIBLE PARTY: DAVID SHAFER

REQUEST: How did East Kentucky Power consider peripheral transmission impacts that could result from this project and what conclusion did you draw?

RESPONSE: The transmission analysis considered impacts on the "monitored" facilities. The monitored facilities included all transmission lines, transformers and buses in the EKPC, BREC, LGEE, and TVA areas and in addition all buses that are connected to these areas up to two additional buses away (ring 2). This resulted in monitoring facilities connected to 2841 buses in 27 control areas. The list of control areas and the number of buses in each area is summarized in the Contingency Processor Area Zone Report included in the CAI January 27, 2005 report Appendices.

In addition, the study results were reviewed with MISO, LGEE, TVA and BREC as described in the Response to Item #1 of this Data Request. MISO performed an independent analysis using their own models and contingency lists and presumably reviewed MISO member transmission facilities nearby to the Kentucky facilities.

Our conclusion is that we have adequately considered a large enough section of the transmission grid to capture the impacts of the proposed changes for the purposes of transmission system planning. These proposed changes will be incorporated into future

NERC, ECAR and MISO planning power flow models and will thereby be available to all NERC, ECAR and MISO members for their own studies and assessments.

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ITEM 9

RESPONSIBLE PARTY: MARY JANE WARNER

REQUEST: List the facilities included in the proposed plan and the major component costs.

RESPONSE: See the attached Exhibits.

Exhibit 9-1 presents the Proposed Plan consistent with the CAI January 27, 2005 Report. The costs included are EKPC's estimates.

Exhibit 9-2 presents the Proposed Plan with all modifications and revisions since the CAI report was published.

EXHIBIT 9-1

PLAN C: PROPOSED WRECC SERVICE ALTERNATIVE - Consistent with CAI January 2005 Report

Project Name	Estimated Cost	Effective Year of Cost	Inflated Cost + IDC	Install Date (Year)
Bristow - Magna 161 kV Line (1 miles 954 MCM)	325,000	2004	341,250	2004
GMC - Magna 161 kV Line (2.5 miles 954 MCM)	875,000	2004	944,900	2005
Magna Substation Terminal Facilities	618,000	2004	667,369	2005
GMC Substation Terminal Facilities	869,000	2004	938,421	2005
Barren Co - Magna 161 kV Line (24 miles 954 MCM)	7,800,000	2004	9,051,667	2008
Barren Co Substation Terminal Facilities	572,000	2004	663,789	2008
GMC - BGMU Tap 161 kV Line (5 miles 954 MCM)	1,625,000	2004	1,885,764	2008
Memphis Jct - BGMU Tap 161 kV Line (8.4 miles 954 MCM, Double Circuit)	3,570,000	2004	4,142,878	2008
Aberdeen - BGMU Tap 161 kV Line (27 miles 954 MCM)	9,275,000	2004	10,763,361	2008
Memphis Jct Substation Terminal Facilities	1,112,000	2004	1,290,443	2008
Aberdeen Substation Terminal Facilities	618,000	2004	717,171	2008
Aberdeen - Wilson 161 kV Line (25 miles 954 MCM)	8,125,000	2004	9,428,820	2008
Wilson (BREC) Substation Terminal Facilities	251,000	2004	291,278	2008
East Bowling Green Substation Terminal Facilities	313,000	2004	363,227	2008
E.Bowling Green - GMC 161 kV Line (.15 miles, 954 MCM, reconductor)	12,000	2004	13,926	2008

Summershade-Barren County 161 kV Line Temp. Upgrade (20.14 miles, upgrade 795 ACSR operating temp. to 212F	17,000	2004	19,728	2008
K30 Switching Substation 69 kV	612,000	2004	710,208	2008
L28 Switching Substation 69 kV	612,000	2004	710,208	2008
Plano-Greenwood Switching Substation 69 kV	612,000	2004	710,208	2008
Franklin 161-69 kV transformer change-out	727,000	2004	843,662	2008
Total ($1,000,000)	**38.5**		**44.5**	

EXHIBIT 9-2

PLAN C (Revised): PROPOSED WRECC SERVICE ALTERNATIVE - Revised to represent updated plans, routing, etc.

Project Name	Estimated Cost	Effective Year of Cost	Inflated Cost + IDC	Install Date (Year)
Bristow - Magna 161 kV Line (1 miles 954 MCM)	325,000	2004	325,000	2004
GMC - Magna 161 kV Line (2.87 miles 954 MCM)	1,219,750	2004	1,317,191	2005
Magna Substation Terminal Facilities	618,000	2004	667,378	2005
GMC Substation Terminal Facilities - Phase 1	290,000	2004	313,171	2005
GMC Substation Terminal Facilities - Phase 2	870,000	2004	1,009,635	2008
Barren Co - Magna 161 kV Line (28.29 miles 954 MCM)	9,498,750	2004	11,023,299	2008
Barren Co Substation Terminal Facilities	715,000	2004	829,758	2008
GMC - BGMU Tap (Steam Plant) 161 kV Line (5.14 miles 954 MCM)	1,799,000	2004	2,087,739	2008
BGMU Tap (Steam Plant)-West Bowling Green Jct. 161 kV Line (5.89 miles 954 MCM)	2,117,000	2004	2,456,779	2008
West Bowling Green Jct.-Memphis Jct. 161 kV Line (3.93 miles 954 MCM, Double Circuit 161 & 69 kV)	1,392,000	2004	1,615,515	2008
West Bowling Green Jct.-Memphis Jct. 161 kV Line (3.93 miles 954 MCM, Single Circuit)	685,740	2004	795,702	2008
West Bowling Green Jct.-Aberdeen 161 kV Line (23.48 miles 954 MCM)	8,174,000	2004	9,483,927	2008
Memphis Jct Substation Terminal Facilities	556,000	2004	645,238	2008
Aberdeen Substation 161 kV Terminal Facilities	618,000	2004	717,190	2008

Aberdeen Substation 69 kV Terminal Facilities	200,000	2004	232,100	2008
Aberdeen - Wilson 161 kV Line (26.79 miles 954 MCM)	8,707,000	2004	10,104,474	2008
Wilson (BREC) Substation Terminal Facilities	1,100,000	2004	1,276,550	2008
East Bowling Green Substation Terminal Facilities	313,000	2004	363,237	2008
E.Bowling Green - GMC 161 kV Line (.15 miles, 954 MCM, reconductor)	24,000	2004	27,852	2008
Summershade-Barren County 161 kV Line Temp. Upgrade (20.14 miles, upgrade 795 ACSR operating temp. to 212F	17,000	2004	19,729	2008
New Salmons 161-69 kV Substation	2,825,000	2004	3,278,413	2008
Salmons-City OF Franklin 69 kV Line (3.9 miles, reconductor with 556 MCM)	357,000	2004	414,299	2008
Plano Switching Substation 69 kV	612,000	2004	710,226	2008
Dewey Lake Junction-Plano 69 kV Line (1.1 miles 556 MCM)	341,000	2004	395,731	2008
69 kV Line Retirements (Steam Plant-Natcher Parkway Jct., etc.)	250,000	2004	290,125	2008
Caneyville 69 kV Tap Line (Purchase or Lease of TVA's Existing Tap Line)	225,000	2004	261,113	2008
Total ($1,000,000)	**43.8**		**50.7**	

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ITEM 10

RESPONSIBLE PARTY: MARY JANE WARNER

REQUEST: What were the preliminary plan components considered but not studied in detail in the CAI study? Provide a high level comparison.

RESPONSE: EKPC considered several potential alternatives to provide service to WRECC that did not require one or more interconnections with TVA in the Bowling Green area. EKPC performed preliminary screening and economic analyses on these alternatives. However, in all cases, the analysis indicated that the components of the proposed EKPC Plan would still be required. Furthermore, all cases would require a new 13.2-mile 161 kV line from Memphis Junction to Salmons in lieu of the interconnection with TVA at Salmons that is part of the proposed EKPC Plan. Also, all alternatives would also require the addition of at least 200 MVAR of 161 kV capacitor banks in the Bowling Green area. The conclusion from this preliminary analysis was that the EKPC Plan represents the most efficient and cost effective expansion option to serve WRECC from the EKPC system.

The alternatives considered that did not establish new interconnections with TVA and their estimated total plan costs are (all plans include the 161 kV lines in the proposed

EKPC Plan, plus the Memphis Junction-Salmons 161 kV line, and the required 161 kV capacitor banks in the area):

> Alternative X1 Description: Construct 23 miles of 345 kV line from LGEE's Smith-Hardin County 345 kV line to the Meredith area. Construct a 345 kV switching substation at the tap point of the 345 kV line and a 345-161-138-69 kV substation at Meredith. Construct 29 miles of 161 kV line from Meredith to General Motors. The estimated cost for this plan in 2008$ is $95.0 million.
>
> Alternative X2 Description: Construct 23 miles of 345 kV line from LGEE's Smith-Hardin County 345 kV line to the Meredith area. Construct a 345 kV switching substation at the tap point of the 345 kV line and a 345-138-69 kV substation at Meredith. Construct 29 miles of 345 kV line from Meredith to General Motors. Construct a 345-161 kV substation at General Motors. The estimated cost for this plan in 2008$ is $106.8 million.
>
> Alternative X3 Description: Construct 55 miles of 161 kV line from BREC's Wilson Substation to General Motors. The estimated cost for this plan in 2008$ is $87.6 million.
>
> Alternative X4 Description: Construct 55 miles of 345 kV line from BREC's Wilson Substation to General Motors. Construct a 345-161 kV substation at General Motors. The estimated cost for this plan in 2008$ is $101.6 million.
>
> Alternative X5 Description: Construct 54 miles of 345 kV line from Marion County to Barren County. Construct a 345-161 kV substation at Marion County and a 345-161 kV substation at Barren County. Construct 26 miles of 161 kV line from Barren County to General Motors. The estimated cost for this plan in 2008$ is $117.0 million.
>
> Alternative X6 Description: Construct 81 miles of 345 kV line from Marion County to Magna. Construct a 345-161 kV substation at Marion County and a 345-161 kV substation at Magna. The estimated cost for this plan in 2008$ is $126.0 million.

Based on the screening results and costs of these alternatives, the decision was made to perform a detailed analysis only of the proposed EKPC Plan, and some variations of it, to ensure that it would provide an adequate and reliable transmission system.

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ITEM 11

RESPONSIBLE PARTY: MARY JANE WARNER

REQUEST: What further development of the proposed plan was made during the routing process?

RESPONSE: The initial planning studies assumed straight-line routes plus a 10% adder for the proposed transmission lines. The routing process resulted in changes to the lengths of these proposed lines. These new mileages and revised cost estimates are reflected in Exhibit 9-2 of the Response to Item #9 of this Data Request. Also, the route selection process resulted in a significant portion of line that was initially assumed to be green field construction in the planning studies being designed as rebuilds of existing lines. Also, co-locating of portions of the Project with existing lines in the area was incorporated into the plan as a result of the route selection process. Additionally, a portion (approximately 36 miles) of the proposed 161 kV line transmission will be constructed using double-circuit structures. The cost estimates in Exhibit 9-2 have also been revised to reflect all of these modifications.

In addition to the changes made as a result of the routing process, the plan has been modified due to other factors. These factors are:

- Substation physical and/or cost modifications based on detailed design analysis
- Substation physical modifications to improve service reliability
- Refinement of plans in Franklin area based on feedback from the City of Franklin municipal electric utility
- Refinement of 69 kV system plans for miscellaneous reasons

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ITEM 12

RESPONSIBLE PARTY: MARY JANE WARNER

REQUEST: Why did CAI and East Kentucky Power select Plan C instead of Plan D?

RESPONSE: Plan D is a modified version of Plan C. This Plan constructs approximately 12 miles of 161 kV line from Aberdeen to the Paradise (TVA)-New Hardinsburg (BREC) 161 kV line. This results in a reduction of about 13 miles of new line construction on into the Wilson Substation, but does require a new 161 kV switching substation where the lines come together. Plan C is estimated to cost approximately $3.5 to $4.5 million more than Plan D. However, Plan C is preferred for the following reasons:

- Total system losses for the four companies in the area are lower by about 2 MW with Plan C. The losses for EKPC and TVA are slightly higher, but the losses for BREC and LGEE are lower.
- The loading on BREC's New Hardinsburg 138-161 kV transformer is a concern. This transformer has experienced a significant number of TLRs. The studies indicate that Plan D results in significantly higher flows on this transformer for versus Plan C. During periods of high north-south transfers and/or outages of the

two Paradise units connected to the 161 kV system, this transformer is more likely to overload if Plan D is implemented.

- BREC has identified a potentially severe double-contingency combination that the Wilson-Aberdeen 161 kV line would alleviate. An outage of both the Wilson-Coleman 345 kV line and the Wilson-Green River 161 kV line is expected to result in a loading of approximately 130% on BREC's Reid-Daviess County 161 kV line. Subsequent tripping of this line is possible at this level of loading, which could result in cascading outages on the BREC system. The Wilson-Aberdeen 161 kV line provides an additional outlet for the Wilson generation, which alleviates this problem. Plan D does not provide the additional outlet for Wilson, and therefore does not provide significant benefits for this scenario.
- Plan C provides a total interconnected capacity between EKPC and BREC of 412 MVA in the summer and 557 MVA in the winter, whereas Plan D provides only 265 MVA of interconnected capacity. Therefore, Plan C will provide the opportunity for a larger level of power transactions between the two companies, if desired.

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ITEM 13

RESPONSIBLE PARTY: MARY JANE WARNER

REQUEST: Describe East Kentucky Power's environmental responsibilities related to the proposed project.

RESPONSE: EKPC is required to follow the environmental policies and procedures established by the United States Department of Agriculture, Rural Utility Service (RUS). The environmental documents will be prepared in accordance with RUS's "Environmental Policies and Procedures" 7-CFR Part 1794. This part contains the policies and procedures of the Rural Utilities Service (RUS) for implementing the requirements of the National Environmental Policy Act of 1969 (NEPA), as amended (42 U.S.C. 4321-4346); the Council on Environmental Quality (CEQ) Regulations for Implementing the Procedural Provisions of NEPA (40 CFR parts 1500 through 1508) and certain related Federal environmental laws, statutes, regulations, and Executive Orders EO) that apply to RUS programs and administrative actions.

As stated in 7-CFR Part 1794:

"This part integrates the requirements of NEPA with other planning and environmental review procedures required by law, or by RUS practice including but not limited to:

(1) Endangered Species Act of 1973 (16 U.S.C. 1531 et seq.);

(2) The National Historic Preservation Act (16 U.S.C. 470 et seq.);

(3) Farmland Protection Policy Act (7 U.S.C. 4201 et seq.);

(4) E.O. 11593, Protection and Enhancement of the Cultural Environment (3 CFR, 1971 Comp., pg. 154);

(5) E.O. 11514, Protection and Enhancement of Environmental Quality (3 CFR, 1970 Comp., p. 104);

(6) E.O. 11988, Floodplain Management (3 CFR, 1977 Comp., p. 117);

(7) E.O. 11990, Protection of Wetlands (3 CFR, 1977 Comp., p. 121);

(8) E.O. 12898, Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations (3 CFR, 1994 Comp., pg. 859).

(d) Applicants are responsible for ensuring that proposed actions are in compliance with all appropriate RUS requirements. Environmental documents submitted by the applicant shall be prepared under the oversight and guidance of RUS. RUS will evaluate and be responsible for the accuracy of all information contained therein."

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ITEM 14

RESPONSIBLE PARTY: MARY JANE WARNER

REQUEST: Describe the steps East Kentucky Power took to solicit concurrence with the short circuit analysis for the proposed plan from other utilities.

RESPONSE: EKPC and WRECC have reviewed the fault current results and determined that there are no significant impacts on existing equipment on either system. The results of the short-circuit analysis will be utilized to ensure that new equipment to be installed as part of the proposed plan has adequate interrupting capabilities for the fault levels expected.

EKPC provided the results of the analysis, including the short-circuit analysis results to TVA and BREC for review periodically throughout the study. Similarly, the results were shared with MISO and LGEE in August 2004, a conference call was held in September 2004, and the final results were shared in January 2005 prior to the CAI report being finalized. Each of these parties was asked to review the results and to advise EKPC if there were any adverse impacts on the respective systems. None of the parties responded specifically regarding the short-circuit analysis results; however, none indicated that the expected fault currents would cause problems with equipment on their respective systems.