COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

A REVIEW OF THE ADEQUACY OF KENTUCKY'S GENERATION CAPACITY AND TRANSMISSION SYSTEM	)))	 ADMINISTRATIVE CASE NO. 387

INTERIM ORDER

On December 20, 2001, the Commission issued an Order in this proceeding setting forth findings on the level of existing and planned generation capacity and the adequacy of the transmission system for Kentucky's six major jurisdictional electric utilities: Big Rivers Electric Corporation ("Big Rivers"), East Kentucky Power Cooperative, Inc. ("East Kentucky Power"), Kentucky Power Company ("Kentucky Power"), Louisville Gas and Electric Company ("LG&E"), Kentucky Utilities Company ("KU"), and The Union Light, Heat and Power Company ("ULH&P") (collectively "the Utilities"). That Order also directed those utilities to conduct two studies and file certain information with the Commission. The Utilities, as ordered, conducted two feasibility investigations: one on joint ownership by non-affiliated companies of future base load generation; the other on coordinating scheduled maintenance of their generating units. The results of the Utilities' studies were submitted in a Joint Feasibility Report ("Report") filed with the Commission on June 28, 2002.

While the Report indicates that the Utilities support the goal of ensuring a continued, reliable source of electricity supply for Kentucky's citizens, it concludes that neither shared ownership of base load generation by non-affiliated companies, nor coordinating scheduled maintenance of generation units, represents a practicable means of achieving this goal. The Utilities' filings and the Commission's assessment thereof are discussed in the following sections of this Order.

Joint Ownership of Base Load Generation by Non-Affiliates

The Utilities conclude that there is a decreased need for, as well as increased difficulties with, joint ownership among non-affiliated companies. They point out that LG&E, Kentucky Power's parent, American Electric Power ("AEP") and ULH&P's parent, The Cincinnati Gas and Electric Company ("CG&E") all have joint ownership experience.

Due to mergers and acquisitions, the major Investor Owned Utilities ("IOUs") subject to Commission jurisdiction have grown in size, increasing their ability to construct new base load facilities without a need for shared ownership. In addition, base load demand is not growing at as great a rate as it did in the 1960's and 1970's. The Report states that today's emphasis is on being better prepared to meet peak demand rather than on meeting intermediate or base load needs. The Report further states that today's more sophisticated forecasting techniques permit all utilities to maintain lower reserve margins. Also, a liquid wholesale market provides an economical option to owning generation since it gives utilities the option to secure power at a cost below that of their own embedded generation.[1]

The Report states that increased competition in energy markets increases the difficulties in synchronizing the operational and business strategies of joint owners of a base load generator because the jointly owned facility would represent only a small

[1] Joint Feasibility Report, Non-Affiliated Joint Ownership, pages 1 and 2, filed June 28, 2002.

portion of each owner's overall generation and purchase portfolio.[2] Operational and strategic differences among owners only increase the risk that the decisions made concerning a utility's generation portfolio may be less financially or operationally feasible under a joint ownership arrangement.[3]

Options Regarding Joint Ownership

The Utilities state that, because of varying needs and resources, the most economical capacity options, including the feasibility of joint ownership, can only be decided on an individual utility basis. They note their own experiences with joint ownership. The Utilities further state that they have had a cooperative relationship and will continue their joint efforts to best meet the needs of their base load customers.

The Report describes the actions taken by East Kentucky Power in connection with its decision to construct a 268 MW coal-fired generating unit in Mason County, Kentucky and the information it provided the Commission as part of the certificate process under KRS 278.020. The Report concludes that the certificate application process provides the Commission with detailed analyses of an individual utility's future load requirements and alternatives for meeting those needs.

The Report also notes that the December 20, 2001 Order required the Utilities to file certain information annually. As set forth in Appendix G of that Order, the Utilities are required to report all planned base load and peaking units needed to meet native load over the next 10 years. In addition, information relating to a planned generating unit's expected in-service date, size and location, as well as other related information

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[2] Id. at 2.

[3] Id. at 3.

must be filed. The Utilities state that they will present the Commission with all options for capacity additions as part of these annual filings.

Finally, the Report states that joint ownership will be among the options considered by the Utilities in developing their respective Integrated Resource Plans ("IRP") pursuant to 807 KAR 5:058. The Report notes that the IRP process has worked for over 10 years without a requirement that an IRP be developed on a joint ownership basis. Rather than imposing such a requirement, the Utilities recommend that joint ownership remain an option to be considered.

In summary, the Report finds that there is a decreased need for and increased difficulties with joint ownership, but the Utilities' certificate requests, their annual reports filed pursuant to this case, and their triennial IRP filings allow the Commission to effectively monitor the viability of joint ownership.

The Commission is well aware that three jurisdictional utilities, or their affiliates, own electric generating facilities jointly with non-affiliates. Since joint ownership by non-affiliates has been successful in the past, the Commission determined that it was appropriate for the Utilities to perform current analysis of its feasibility. As KU/LG&E reported last year in an annual update, they are considering a new coal-generating unit whose ownership may be shared with a non-affiliate. The existence of shared ownership by non-affiliates indicates that such arrangements are reasonable under certain circumstances. The Commission does have the ability to review capacity addition plans, including joint ownership, in generation certificate and IRP cases, as well as in the annual filings on planned generation submitted pursuant to the December

2001 Order in this case. Therefore, the Commission expects the Utilities to continue to consider joint ownership opportunities in the IRP process and certificate cases.

Coordination of Shared Maintenance Schedules

The Report concludes that there are several factors, including potential violation of anti-trust laws that preclude further consideration of this issue. The Report states that generation outage plans contain confidential and competitively sensitive information that would be valuable to other utilities in today's competitive wholesale market. The Report further states that voluntary disclosure and coordination of maintenance information could result in claims of anti-competitive behavior. The Utilities state that there is no need for such coordination since future maintenance schedules are reported to the East Central Area Reliability Council ("ECAR") on a unit-by-unit basis for a 4-week period. ECAR, in turn, issues weekly reports on the aggregate generation scheduled to be out of service.[4] The Utilities state that, considering ECAR's oversight of reporting and coordinating maintenance activities, and weighing the risk of antitrust allegations, such mutual coordination is not an appropriate means of addressing the Commission's concerns.[5] The Utilities also state that ECAR, with its focus on near-time operational periods, will be able to identify potential issues arising from planned maintenance.

Further, the Utilities state that Regional Transmission Organizations ("RTOs") should help mitigate potential risks associated with independently determined maintenance. They also cite the manner in which they schedule maintenance as

[4] Joint Feasibility Report, Shared Maintenance Schedule, page 1, filed June 28, 2002.

[5] Id. at 2.

another reason for the lack of need for coordination. Scheduled maintenance typically occurs in the shoulder, or lower peak, months of the spring or fall, rather than in summer or winter to avoid simultaneous outages that could cause reliability problems.[6] In addition, some of the Utilities are winter peaking while others are summer peaking. The Utilities further state that maintenance schedules are continually revised in response to a number of variables.[7]

With regard to control area economics, the Utilities state that they dispatch generation to meet their loads while balancing several factors to meet their own real-time demands in an economic fashion. They further state that it is inappropriate to require a utility to adopt a maintenance schedule that is economically optimized for anything other than its own system since electric rates for Kentucky customers are not based on the collective revenue requirements of all utilities.[8] The Utilities also state that they use several different computer programs to assist in the development of optimal outage plans, that these programs are often embedded within their larger energy management systems, and are not easily integrated.

The Report concludes that the Utilities "uniformly believe that any conceivable benefits of a coordinated effort involving the sharing of maintenance schedules are significantly outweighed by not only the risks of antitrust litigation, but also by practical considerations showing that such coordination will not further the Commission's goals."[9]

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[6] Id. at 2.

[7] Id. at 3-4.

[8] Id. at 3.

[9] Id. at 4.

The Commission generally agrees with the positions presented by the Utilities. We understand that it is standard practice to schedule outages during times of low demand in the shoulder months and that utilities will plan to have adequate generation, either through energy or capacity purchases, as the risks warrant, to meet native load. The Commission also acknowledges the important role played by ECAR in the coordination of maintenance activities. However, the Commission believes that the role of RTOs is too ambiguous at this time for the RTOs to be relied on to mitigate potential risk associated with independently scheduled maintenance. In addition, neither Big Rivers nor East Kentucky Power is a member of an RTO and KU/LG&E are seeking Commission approval to withdraw from the Midwest Independent System Operator ("MISO").

However, if there was a need to coordinate, the Commission expects that the other considerations noted in the Report could be satisfactorily addressed. For example, if a utility needed to delay maintenance to accommodate another utility's schedule, then the two utilities could construct an arrangement to compensate the utility for the delay. Utilities currently exchange capacity and energy on a daily basis for the purpose of economically serving their own loads, and, while it is only one of numerous variables, maintenance outages receive strong consideration in planning and conducting such exchanges.

The electric utility industry is undergoing change with new issues continuously arising. The Commission, therefore, encourages the Utilities to continue to review shared maintenance schedules and to include an assessment of this issue in each IRP filing. The Commission remains concerned about the potential efficiencies and benefits from shared maintenance schedules and will investigate any event that results in significant customer outages related to the inability to exchange capacity due to scheduled maintenance outages.

Projected Reserve Margins – 2002/2003/2004

Planning reserve margins, stated as a percentage of demand, were filed by the Utilities in March 2002 and updated in July 2002, filed in March 2003 and updated in July 2003, and filed in March 2004.

As a member of the AEP system, Kentucky Power reported for 2002, 2003 and 2004 that it has no target reserve margin, but that AEP operates at an ECAR-prescribed operating reserve of 4 percent of peak daily load.[10] Kentucky Power reported that AEP, as a system, uses a 12 percent planning margin during seasonal peaks.[11] ULH&P reported that it has a full requirements wholesale contract through 2006 and has a target reserve margin of 15 percent thereafter.[12] Big Rivers reported that it purchases firm power for native load and has no formal planning reserve margin.[13] KU/LG&E,

[10] AEP operates the AEP-East and AEP-West systems. Kentucky Power is a member of AEP-East. AEP-West does not operate under ECAR requirements.

[11] Response of Kentucky Power to Appendix G, Item 7, dated March 1, 2002, Item 7, dated February 28, 2003, and Item 7, dated March 1, 2004.

[12] Response of ULH&P to Appendix G, Item 7, dated July 1, 2003.

[13] Response of Big Rivers to Appendix G, Item 7, dated March 1, 2002, Item 7, dated March 17, 2003, and Item 7, dated March 1, 2004.

operating as a combined system, reported a target reserve margin of 14 percent[14] while East Kentucky Power now has a 12 percent target reserve margin.[15]

In March 2002, KU/LG&E projected no deficits, but showed reserve margins falling from 16.8 percent in 2002 to 14.4 percent in 2006.[16] The 2002 IRP filed by KU/LG&E on October 1, 2002 includes a new reserve margin study that calls for a range of 13 to 15 percent, with 14 percent as the target. Their previous study, prepared in 1999, included a range of 11 to 14 percent with 12 percent as the target. In March 2003, KU/LG&E projected their margins increasing from 13.7 percent in 2003 to 14.7 percent in 2006. With four combustion turbines ("CTs") of 150 MW each available in 2004, the March 2004 report for KU/LG&E shows a range of projected reserve margins of 26.2 percent in 2004 to 16.6 percent in 2008.[17]

In March 2002, Kentucky Power projected a reserve deficit in its winter peak season growing steadily from -5.5 percent in winter 2002 to -12.9 percent in winter 2006. The projections did not include transactions to maintain reserves by or between the members of AEP-East.[18] In March 2003, Kentucky Power's updated projections

[14] Response of LG&E to Appendix G, Item 7, dated February 28, 2003 and Item 7, dated March 1, 2004, and Response of KU to Appendix G, Item 7, dated February 28, 2003 and Item 7, dated March 1, 2004.

[15] Response of East Kentucky Power to Appendix G, Item 7, dated March 7, 2003, and Item 7, dated March 1, 2004.

[16] Response of LG&E to Appendix G, Item 8, dated March 1, 2002, and Response of KU to Appendix G, Item 8, dated March 1, 2002.

[17] Response of LG&E to Appendix G, Item 8, dated February 28, 2003 and Item 8, dated March 1, 2004, and Response of KU to Appendix G, Item 8, dated February 28, 2003 and Item 8, dated March 1, 2004.

[18] Response of Kentucky Power to Appendix G, Item 8, dated March 1, 2002.

reflected a reserve deficit in its winter peak season growing from –6.6 percent in winter 2003 to –10.5 percent in winter 2006.[19] The response submitted for 2004, again shows an increase in the deficit from –12.6 in 2003/2004 to –15.1 percent in 2007/2008.[20]

In 2002, 2003 and 2004, Big Rivers stated that it purchased its full requirements and that its level of firm capacity purchases for the next 5 years of 775 MW is sufficient to meet its members' requirements.[21] Under its specific operating conditions, Big Rivers' 2002 IRP does not reflect any changes in its reserve margin requirements.

In March 2002, East Kentucky Power projected winter reserve margins falling from 10.0 percent in 2002 to 6.6 percent in 2006, with summer margins growing from 12.0 percent in 2002 to 15.2 percent in 2006. In March 2003, East Kentucky Power reported a reduced target reserve margin of 12 percent. East Kentucky Power currently has less than a 12 percent reserve margin, but expects to be near a 12 percent level for the summer peak of 2005 following commercial operation of the 268 MW Gilbert unit in April 2005.[22] In March 2004, East Kentucky Power reported a target reserve margin of 12 percent. East Kentucky Power again reported a reserve margin of less than 12 percent, but projects its reserve margin to grow to over 12 percent in 2007 and 2008. In

[19] Response of Kentucky Power to Appendix G, Item 8, dated February 28, 2003.

[20] Response of Kentucky Power to Appendix G, Item 8, dated March 1,2004.

[21] Response of Big Rivers to Appendix G, Item 8, dated March 1, 2002, Item 8, dated March 17, 2003, and Item 8, dated March 1, 2004.

[22] Response of East Kentucky to Appendix G, Item 8, dated March 1, 2002, and Item 8, dated March 7, 2003.

its March 2004 report, East Kentucky Power discusses its plans for capacity additions and possible additional seasonal power purchases.[23]

In July 2002, ULH&P reported that its firm capacity purchases equal its net firm load and were projected to grow from 815 MW in 2002 to 861 MW in 2006.[24] In the July 2003 update, ULH&P reported that firm capacity purchases and load were expected to grow from 843 MW in 2003 to 877 MW in 2006.[25] On July 21, 2003, in Case No. 2003-00252,[26] ULH&P filed a request for approval to acquire 1,105 MW of generating capacity from CG&E. The Commission preliminarily approved ULH&P's request on December 5, 2003. At the time of the transfer, ULH&P expects to have a reserve margin of about 27 percent. ULH&P will file a stand alone IRP in 2004. The March 2004 report includes information based on the assumption that the planned acquisition will be completed by July 1, 2004. The report shows projected reserve margins declining from 28.4 percent in 2004 to 20.2 percent in 2008.[27]

With the exception of Kentucky Power, the Commission accepts the Utilities' analysis of reserve margins. The Commission will, however, continue to review reserve

[23] Response of East Kentucky Power to Appendix G, Item 8, dated March 1, 2004.

[24] Response of ULH&P to Appendix G, Item 8, dated June 28, 2002.

[25] Response of ULH&P to Appendix G, Item 8, dated July 1, 2003.

[26] Case No. 2003-00252, Application of The Union Light, Heat and Power Company For a Certificate of Public Convenience and Necessity to Acquire Certain Generation Resources and Related Property; For Approval of Certain Purchase Power Agreements; For Approval of Certain Accounting Treatment; and For Approval of Deviation From Requirements of KRS 278.2207 and 278.2213(6).

[27] Response of ULH&P to Appendix G, Item 8, dated March 1, 2004.

margins as part of the IRP process. The issue of Kentucky Power's reserve margin is addressed in the next section on generating capacity additions.

Capacity Additions

Each utility filed information relative to its plans for capacity additions to meet native load requirements over the next 10 years. A summary of the information, by utility, follows:

Kentucky Power – In 2002, 2003 and 2004, Kentucky Power reported that there were no current plans for capacity additions for Kentucky Power or any AEP-East member.[28]

Big Rivers – In 2002, 2003 and 2004, Big Rivers reported no plans for construction of any capacity additions.[29]

East Kentucky Power – The capacity additions reported for 2002, 2003 and 2004 for East Kentucky Power include the 268 MW Gilbert Unit; seven CTs at its Smith site, each with a capacity of 100 MW; up to 50 MW of landfill gas generation at various sites; and a second 268 MW coal-fired unit. This nearly 1,300 MW of capacity is expected to be installed between 2004 and 2011. The March 2004 report includes two peaking CTs totaling 100 MW with an in-service date in 2013.[30]

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[28] Response of Kentucky Power to Appendix G, Item 12, dated March 1, 2002, Item 12, dated February 28, 2003, and Item 12, dated March 1, 2004.

[29] Response of Big Rivers to Appendix G, Item 12, dated March 1, 2002, Item 12, dated March 17, 2003, and Item 12, dated March 1, 2004.

[30] Response of East Kentucky Power to Appendix G, Item 12, dated March 1, 2002, Item 12, dated March 7, 2003, and Item 12, dated March 1, 2004.

KU/LG&E - The July 2003 assessment filing updating planned capacity additions is unchanged from the previous filing. Through 2010, KU and LG&E expect to add four CTs at LG&E's Trimble County site and two Greenfield CTs, each with a capacity of approximately 150 MW. Also under review is construction of a 732 MW supercritical coal unit at LG&E's Trimble County site with the KU/LG&E ownership share being 75 percent, or 549 MW. The March 2004 report reflects the same information and notes that the baseload need (Trimble County) noted above and identified in the 2002 IRP is still being evaluated.[31]

ULH&P – In 2002, ULH&P reported no specific plans for capacity additions but noted that it is required to file a formal IRP in 2004.[32] As previously noted, in 2003, in Case No. 2003-00252, ULH&P filed a request for approval to acquire 1,105 MW of generating capacity from CG&E. The Commission preliminarily approved ULH&P's request on December 5, 2003. The March 2004 report includes the information noted above assuming that acquisition will be complete by July 1, 2004.[33]

As with the analyses of reserve margins, with the exception of Kentucky Power, the Commission accepts the information provided on capacity additions. The Commission will continue to review information on capacity additions as part of the IRP process and in appropriate certificate cases.

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[31] Response of LG&E to Appendix G, Item 12, dated February 28, 2003 and Item 12, dated March 1, 2004, and Response of KU to Appendix G, Item 12, dated February 28, 2003 and Item 12, dated March 1, 2004.

[32] Response of ULH&P to Appendix G, Item 12, dated June 28, 2002.

[33] Response of ULH&P to Appendix G, Item 12, dated March 1, 2004.

As for Kentucky Power's reserve margins and capacity addition plans, as a member of the AEP system, Kentucky Power is required to participate in the AEP power pool. Kentucky Power has two wholesale purchase power contracts with an affiliate owned generating unit in Rockport, Indiana ("Rockport"). This arrangement is set to expire on December 31, 2004. On December 17, 2002, the Commission approved an extension of these contracts as part of its approval of an overall restructuring of AEP in Case No. 2002-00039.[34] As approved, these contract extensions would maintain Kentucky Power's existing generating capacity for the next several years. However, at an informal conference on February 7, 2003, AEP explained that it would not extend the Rockport contracts due to its decision to forego its restructuring plan.

In its Order approving AEP's corporate restructuring, the Commission found that extending the Rockport purchase power contracts was in the best interest of Kentucky Power and its ratepayers. Absent any evidence to show that these contract extensions are detrimental to ratepayers, Kentucky Power should take the necessary steps to secure the contract extension prior to December 30, 2004.

[34] Case No. 2002-00039, Joint Application of Kentucky Power Company d/b/a American Electric Power, American Electric Power Company, Inc. and Central and South West Corporation for (1) Approval of the Changes to the System Sales Clause Tariff; (2) Entry of Certain Findings Pursuant to 15 U.S.C. 97Z; (3) Entry of Certain Findings Pursuant to 17 C.F.R. 200.53; (4) the Entry of an Order Declaring That the Transfer of the Stock of Kentucky Power Company From American Electric Power Company, Inc. to Its Wholly Owned Subsidiary, Central and South West Corporation May Be Consummated Without Approval by the Commission; or, Alternatively, Approving the Transfer Pursuant to KRS 278.020(4) and KRS 278.020(5); and (5) For Related Relief.

Transmission

The Utilities were requested to provide information related to transmission congestion and planned capacity additions for the next 10 years. None of the Kentucky jurisdictional electric utilities have plans for major transmission capacity additions other than for normal system development and load growth to serve native load. Kentucky Power did note that AEP's planned Wyoming-Jackson's Ferry 765 kV line in West Virginia will provide collateral benefits to Kentucky Power's customers.[35]

In its 2002 response, East Kentucky Power stated that it normally prepares a detailed list of transmission facility additions for a 3-year planning horizon and that less detail is placed on facilities for the remaining 10-year planning horizon. East Kentucky Power provided a brief description of five transmission facilities identified for the 10-year planning horizon as well as a detailed list of transmission projects for the 3-year planning period. East Kentucky Power stated that these improvements are to serve native load customers and not to provide for large wholesale power transfers. While East Kentucky Power noted that marketer transactions between the ECAR region and the Tennessee Valley Authority ("TVA") periodically cause overloads on its transmission system, it also stated that although the listed additions could have significant effects on transmission, none are required for constraints, bottlenecks or transmission system problems.[36] East Kentucky Power's March 2003 filing reflects the same information it provided in 2002; however, its July 2003 supplement provides several additions and

[35] Response of Kentucky Power to Appendix G, Item 14, dated February 28, 2003.

[36] Response of East Kentucky Power to Appendix G, Item 14, dated March 1, 2002.

deletions to the transmission project list. The March 2004 report provides the same information included in the July 2003 supplement.[37]

In its 2002 response, ULH&P provided a list of five transmission projects planned to be placed in-service in 2002 or 2003, stating that they were needed for local load growth.[38] Its 2003 response lists four transmission projects to be completed in the 2003-2005 time frame, also stating that they are for local load growth. The March 2004 report lists six transmission projects to be completed between 2004 and 2005, all for local load growth.[39]

In its 2002 response, with the exception of AEP's Wyoming-Jackson's Ferry 765 kV line in West Virginia, Kentucky Power had not identified any expansion projects of its own to serve its native load through 2011. The proposed Wyoming-Jackson’s Ferry line has been pending approval in West Virginia for over a decade due to siting concerns. While it will not actually be built in Kentucky, the line would provide another outage contingency for southeastern Kentucky. Kentucky Power stated that the planning horizon for lower voltage lines was about 2 years, while the planning horizon for 138 kV and higher transmission was 5 years. Kentucky Power also stated that it might be necessary to expand its transmission system to connect Independent Power Producers (“IPPs”), but that the IPPs would fund construction of these lines.[40] Kentucky Power’s

[37] Response of East Kentucky Power to Appendix G, Item 14, dated February 28, 2003, Item 14, dated July 1, 2003, and Item 14, dated March 1, 2004.

[38] Response of ULH&P to Appendix G, Item 14, dated June 28, 2002.

[39] Response of ULH&P to Appendix G, Item 14, dated July 1, 2003 and Item 14, dated March 1, 2004.

[40] Response of Kentucky Power to Appendix G, Item 14, dated March 1, 2002.

2003 response included the same information but updated the status of the IPPs. As of February 28, 2003, there were two IPPs totaling 835 MW interconnected to the Kentucky Power system. Both are located adjacent to Kentucky Power's Big Sandy plant. A third IPP, Kentucky Mountain Power, LLC/Enviropower, LLC ("Kentucky Mountain Power"), with plans for approximately 500 MW of capacity, has entered into an interconnection agreement with Kentucky Power. If built, that unit would require the construction of about 40 miles of 138 kV line. The March 2004 report notes that the interconnection agreement with Kentucky Mountain Power expired in early 2004 but that Kentucky Mountain Power has petitioned the Federal Energy Regulatory Commission to extend the agreement for one year.[41]

In its 2002 response, Big Rivers provided a list of transmission projects planned through 2011, stating that they were needed for meeting member cooperative load growth. Big Rivers also stated that if load patterns changed from its forecast, the transmission plan would be altered accordingly.[42] The lists of transmission projects included in Big Rivers' 2003 and 2004 responses are essentially the same as provided in its 2002 response.[43] Big Rivers states that the planned transmission projects are needed to meet member cooperative load growth.

In the 2002 response, KU/LG&E provided a list of transmission projects planned through 2010. KU and LG&E stated that the planned additions were to serve network

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[41] Response of Kentucky Power to Appendix G, Item 14, dated February 28, 2003 and Item 14, dated March 1, 2004.

[42] Response of Big Rivers to Appendix G, Item 14, dated March 1, 2002.

[43] Response of Big Rivers to Appendix G, Item 14, dated March 17, 2003 and March 1, 2004.

load and that none of the projects were to increase export capacity or relieve parallel flow problems.[44] The list of transmission projects included in the 2003 response is essentially the same as provided in the 2002 response. KU and LG&E again stated that the planned transmission projects are to serve network load and that none of the projects were to increase export capacity or relieve parallel flow problems.[45]

As part of a review of the August 14, 2003 blackout, the Commission has employed Commonwealth Associates, Inc. ("CAI") to update its review of Kentucky's transmission system. The Commission has determined that findings related to the transmission information provided by the Utilities would be premature until the completion of the CAI review, which is anticipated to be filed no later than June 30, 2004.

Other Developments – Merchant Plants, TVA

Other than their potential impact on the transmission system, at the time of the issuance of the Order in Administrative Case No. 387 on December 20, 2001, it appeared that there would be little impact from merchant plants on the jurisdictional utilities' use of their respective transmission systems to serve native load customers.

As of May 16, 2001 when the Energy Policy Advisory Board was established, the Commission was aware of plans for 19 merchant plants in Kentucky. However, by the end of December 2003, only 5 entities had given notice of plans to submit applications for generation construction certificates to the Kentucky State Board on Generation and

[44] Response of LG&E to Appendix G, Item 14, dated March 1, 2002, and Response of KU to Appendix G, Item 14, dated March 1, 2002.

[45] Response of LG&E to Appendix G, Item 14, dated February 28, 2003, and Response of KU to Appendix G, Item 14, dated February 28, 2003.

Transmission Siting ("Siting Board"). Of those five, only three had actually submitted applications to the Siting Board. In 2002, Kentucky Mountain Power was granted a conditional certificate to construct a 520 MW coal and waste coal-fired plant.[46] In 2003, Kentucky Pioneer Energy, LLC ("KPE") was also granted a conditional certificate to construct a 540 MW gasification combined cycle facility. An application from Thoroughbred Generating Company, LLC to construct a 1500 MW coal-fired facility was also granted conditionally by the Siting Board.[47] While the Siting Board's decision in each of these cases was challenged in court, the Kentucky Mountain Power case has been resolved.

Prior to the creation of the Siting Board, other merchant plants that had received environmental permits began construction. Those include Dynegy's Riverside and Foothills generation projects located adjacent to Kentucky Power's Big Sandy Plant and Dynegy's Bluegrass generation project located in Oldham County, Kentucky. Construction of those generators has been completed and all three are operational.

At the time of the Commission's December 20, 2001 Order, the Enron bankruptcy and related events were just beginning to have an impact on the restructuring of the electric industry and the construction of merchant power plants. Since then, the full impact of the Enron situation and other events has significantly decreased the number of proposed merchant plants. In Kentucky, only KPE has

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[46] Case No. 2002-00149, The Application of Kentucky Mountain Power, LLC/ Enviropower for a Merchant Power Plant Construction Certificate in Knott County, Kentucky Near Talcum, final Order Dated September 5, 2002.

[47] Case No. 2002-00150, The Application of Thoroughbred Generating Company, LLC for a Merchant Power Plant Construction Certificate in Muhlenberg County, Kentucky, final Order Dated December 5, 2003.

contracted with a buyer (East Kentucky Power) to purchase the generation output of its proposed facility. However, the KPE project has been repeatedly delayed from its originally projected in-service date of 2003/2004 to 2008. Because of its generation needs and its concern that KPE may not be constructed, East Kentucky Power requested and received a certificate to construct the Gilbert facility, a 268 MW coal–fired unit. East Kentucky Power has started construction of the Gilbert facility with a scheduled in-service date of spring 2005. The Commission is currently considering the need for East Kentucky Power to continue its purchase power contract with KPE and the need for the Gilbert unit in Case Nos. 2000-00079 and 2003-00030.[48]

The Commission does not believe that any significant portion of the generation needed to serve the native load of Kentucky's six jurisdictional utilities will be met by merchant plants in the near future. If anything, it now appears that there is less likelihood of the availability of merchant power than at the time of the December 20, 2001 Order.

Finally, the Commission was recently made aware that several of TVA's full–requirements Kentucky customers had given notice to TVA of their intention to seek an alternate source of supply at the end of their current contracts. Apparently, municipal and cooperative wholesale customers have given notice of this intention as well as several TVA direct serve industrial customers in the Calvert City area. The future impact of the actions taken by these current TVA customers is uncertain at this time.

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[48] Case No. 2000-00079, The Application of East Kentucky Power Cooperative, Inc. for Approval to Purchase Power Agreement; Case No. 2003-00030, An Investigation of East Kentucky Power Cooperative, Inc.'s Need for the Gilbert Unit and the Kentucky Pioneer Energy, LLC Purchase Power Agreement.

SUMMARY OF FINDINGS

The Commission, based on the evidence of record and being otherwise sufficiently advised, finds that:

1. There is not a current need for joint ownership of generating facilities. However, the Utilities should affirmatively consider joint ownership opportunities when planning new generation. Future IRP filings and certificate applications should include specific discussion relative to joint ownership considerations.

2. There is not a current need for coordination of maintenance schedules beyond that in place at ECAR. The Commission encourages the Utilities to continue to review the issue of shared maintenance schedules and to include an assessment in each IRP filing. The Commission will investigate any event that results in significant customer outages related to the inability to exchange capacity due to scheduled maintenance outages.

3. With the exception of Kentucky Power, the Commission accepts the Utilities' individual analyses of their reserve margin requirements. However, reserve margins will continue to be reviewed as part of the IRP process and in certificate proceedings. The Commission will address the issue of Kentucky Power's reserve margins as part of its review of the IRP scheduled to be filed by June 30, 2006, as ordered in Case No. 2002-00039.

4. As with the analyses of reserve margins, with the exception of Kentucky Power, the Commission accepts the Utilities' individual information regarding capacity additions. The Utilities should continue to consider the purchase of merchant power in their IRPs. The IRPs should include any consideration of the TVA wholesale customers

to the extent practical given the uncertainties involved. The Commission will address the issue of Kentucky Power's need for additional capacity and the Rockport contract extensions in the near future.

5. The Commission will address transmission-related issues following the completion of the CAI report, which is expected to be filed no later than June 30, 2004.

IT IS THEREFORE ORDERED that:

1. The Utilities shall continue to consider joint ownership opportunities when planning new generation. Future IRP filings and certificate applications shall include specific discussion relative to joint ownership considerations.

2. The Utilities shall continue to review shared maintenance schedules and include an assessment thereof in each IRP filing.

3. The Utilities' analysis of reserve margins shall continue to be included in their IRP filings.

4. The Utilities shall continue to consider the purchase of merchant power as part of their IRPs. The Utilities' IRPs shall include consideration of TVA wholesale customers to the extent practical given the uncertainties involved.

5. The Utilities shall continue to file the information set forth in Appendix G of our December 20, 2001 Order, with the exception of Items No. 1, 2, 5, 9, and 10, by March 1 of each year. The requirement to file mid-year updates is terminated.

Done at Frankfort, Kentucky, this 29th day of March, 2004.

By the Commission

ATTEST:

Executive Director