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BEFORE THE STATE CORPORATION COMMISSION
OF THE STATE OF KANSAS

Testimony of J. Bertram Solomon
GDS Associates, Inc.

On Behalf of
KANSAS ELECTRIC POWER COOPERATIVE, INC.

DOCKET NO. 08-KEPE-597-RTS

December 21, 2007

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is J. Bertram Solomon. I am a consultant specializing in public utility economics. My business address is GDS Associates, Inc., Suite 800, 1850 Parkway Place, Marietta, Georgia 30067.

Q. Please outline your background and relevant experience.

A. I received the degree of Master of Business Administration from Georgia State University in 1973. My area of concentration was Finance. I also received the degree of Bachelor of Science in Industrial Management from the Georgia Institute of Technology in 1972.

My work experience began as a cooperative student at Georgia Tech, where I gained approximately two years experience as an assistant engineer in an industrial production setting. After graduation from Georgia Tech in 1972, I worked approximately one and one-half years as a program manager for a management consulting firm and for another one and one-half years as a project analyst for a resort development firm.

I began consulting regarding electric utility-related issues when I was employed by Southern Engineering Company in January 1975. For the next eleven years, I worked on assignments in both the retail and wholesale rate departments of Southern Engineering, primarily in the area of electric utility rates. In February 1986 I left Southern to co-found GDS Associates, Inc., a public utility engineering and consulting firm providing integrated resource planning services, generation support services, financial and statistical services, and regulatory services nationwide. I now serve as Vice President and Treasurer for GDS.

During my career, I have provided expert testimony before the public utility commissions of Alaska, Arkansas, Florida, Georgia, Indiana, Kentucky, Maine, Michigan, Minnesota, Nevada, New Jersey, North Carolina, Ohio, Oklahoma, Pennsylvania, Rhode Island, South Carolina, Texas, Virginia, and the State Corporation Commission of Kansas ("Commission") and before the Federal Energy Regulatory Commission ("FERC"). The areas of my expert testimony have included, among others: various financial issues such as capital structure, required rates of return for investor-owned utilities and required margin levels for electric cooperatives; proper methods of measuring working capital requirements; the effects of alternative accounting methods on expenses, income taxes, revenues, rate base and cost of capital and their proper treatment for ratemaking purposes; reasonableness and prudency of various utility investments and expenditures; proper methods of cost allocation; rate design; integrated resource planning; the proper unbundling of rates by service function; electric utility industry restructuring issues; various regulatory policy issues and economic feasibility analyses. I have presented testimony in water, natural gas and electric cases. I also have prepared and filed comments before various commissions in generic and rulemaking proceedings, and I have testified before state and federal legislative bodies. In addition, I have participated in the preparation of retail and wholesale allocated cost of service studies, power cost projections, generating plant joint venture feasibility analyses, and I have been responsible for competitive power supply solicitations, resulting contract negotiations and related litigation efforts.

Q. In what cases have you provided expert testimony before regulatory commissions?

A. As previously indicated, I have provided expert testimony in numerous cases before various public utility regulatory commissions. A list of these cases is provided in the attached Exhibit JBS-1. In addition to providing testimony in those cases, I have participated in the successful negotiation of settlements in many other cases filed before public utility regulatory commissions, thus eliminating the necessity of filing testimony in those proceedings.

Q. On whose behalf are you appearing in this proceeding?

A. I am appearing on behalf of Kansas Electric Power Cooperative, Inc. ("KEPCo").

Q. What is the purpose of your testimony?

A. I was asked by KEPCo to conduct a financial assessment in light of KEPCo's currently deteriorating financial condition and to provide recommendations to reverse this trend. This assignment also included the development of recommended times interest earned ratio ("TIER") and/or debt service coverage ("DSC") targets for purposes of establishing KEPCo's margin requirements for its rate filing. The purpose of my testimony is to present the results of my analyses and my recommended financial plan for KEPCo including the use and level of DSC I recommend as the primary means of determining the margin component of KEPCo's test year revenue requirement for purposes of establishing its wholesale rates to its Members.

Q. Did you prepare a report summarizing your analyses and resulting recommendations for presentation to KEPCo's Board of Trustees?

A. Yes. My report, the KEPCo 2007 Financial Plan and Analysis of Margin Requirements, is included in the filing as Section 14. My report contains a thorough discussion of our study methodology, the analyses conducted, our application of KEPCo's existing financial policy guidelines, and the rationale and support for my recommendations. Therefore, I rely on the report as part of my testimony and will not repeat its details in the body of this testimony.

Q. What recommendations did you make as a result of your financial review and analyses?

A. My recommendations were as follows:

A. Add a demand-related purchased power adjustment provision to KEPCo's member rates.

B. Seek to build and maintain a year-end cash balance of at least $14 million.

C. Maintain KEPCo's current line of credit of $15 million.

D. Continue the existing policy of seeking to build equity to 20% of assets on a GAAP accounting basis.

E. Use an annual DSC target of 1.2.

F. Continue the policy of targeting a minimum TIER of 1.2, but recognizing that TIER will not be the primary focus of financial evaluations of KEPCo over the next several years.

G. Evaluate KEPCo's progress in attaining these financial goals annually as a part of the regular rate review and re-evaluate the targets in 1-2 years.

Q. Were your recommendations adopted by KEPCo's Board?

A. Yes. The Board Resolution adopting my report and recommended financial plan is attached as Exhibit JBS-2.

Q. How does the adoption of your recommendations impact this rate filing?

A. My recommended financial plan has both short-term and long-term implications. In the short term, KEPCo needs to rebuild its cash balances to a reasonable level. Over the longer term, KEPCo needs to build a reasonable level of equity capital. The first step to meeting both of these goals is the use of a target DSC ratio of 1.2. Also, in order to provide greater long-term stability to KEPCo's future margin levels, I have recommended the addition of a demand-related purchased power cost adjustment provision to its member rates. Thus, the immediate impact of my recommendations on KEPCo's rate filing is the use of a test year margin level that will produce a 1.2 DSC and the inclusion of a demand-related purchased power cost adjustment provision.

Q. Recognizing that detailed support for your recommendations is included in Section 14, please summarize the major reasons why KEPCo's rates should be set with a margin level targeted to produce a 1.2 DSC.

A. KEPCo's last rate change was in February 2002, and, as a result of increases in costs, recent changes in KEPCo's power supply contracts, and other factors, KEPCo's financial condition has deteriorated and is expected to continue to worsen in the future under present rates. Therefore, KEPCo must increase its wholesale rates and modify its rate design in order to meet the requirements of its financial policy, its mortgage indenture, and to attain a financially sound footing on which to engage the increasingly challenging and competitive electric utility environment.

Events subsequent to KEPCo's last rate case have caused the focus on cash requirements to become even more important to its rate determinations. KEPCo now requires substantially more cash to meet the growing principal payment requirements on its current and upcoming loans than is generated through the depreciation and amortization components of its current rates and than will be built into its new rates. This means that the additional cash required to make the full amount of these principal payments must come from increased margins built into the rates. Thus, DSC and cash requirements have now become the primary factors that determine the margin component of KEPCo's future revenue requirements and rates, rather than its accrual accounting (or income statement) based TIER target. Therefore, I am recommending use of a 1.2 DSC, with an appropriate demand-related purchased power cost adjustment ("PPCA") mechanism, rather than a 1.2 TIER, for determining KEPCo's margin requirement in its rates.

The recommended addition of a demand-related PPCA is important to building and maintaining KEPCo's financial integrity due to the significant lag that KEPCo experiences in the process of considering, developing, filing, and implementing rate changes. In addition, the demand-related costs for purchases under KEPCo's proposed new Westar purchased power contract that has not yet been approved by the FERC will be based on formulary rates that will change annually to track changes in Westar's fixed costs. Such changes could be large in some years, and KEPCo needs to be able to track such changes in its rates on a reasonably timely basis. In the event that KEPCo is not allowed to add the demand-related PPCA, then I would recommend use of a 1.3 DSC, which is near (albeit a little less) that which Commission Staff witness Rohrer testified would be produced as a result of using his recommended 1.30 TIER for the test year in KEPCo's last rate proceeding.

Q. Do recent financial results demonstrate the need to focus on the DSC requirement in setting KEPCo's rates?

A. Yes. As shown on page 10, Table 1 of Section 14, while KEPCo experienced TIERs of 1.39 and 1.12, respectively, in 2005 and 2006 and is expected to have a TIER of 1.23 for 2007, its comparable DSCs were 1.08 in 2005, dropping to 0.94 in 2006, and is expected to be 0.98 in 2007. This is a vivid example of how KEPCo's TIER and DSC ratios are diverging due to its higher annual loan principal payments than its depreciation and amortization expenses, and demonstrates the pressing need to change rates with its margin requirement determined using the DSC rather than TIER target. Without that, KEPCo will be in danger of failing to meet its mortgage requirement to achieve an average of at least 1.0 DSC for the best two out of the last three years.

Q. What other major concerns are driving your recommendations?

A. KEPCO's year-end cash balances have dropped significantly from $9.4 million at the end of 2004 to $3.3 million at the end of 2006, with a little improvement by the end of 2007 due only to additional borrowing by KEPCo. In fact, KEPCo's 2007 year end cash balance forecast of $6.1 million includes receipt of a $5.9 million loan from the Rural Utilities Service (RUS) in the later part of the year. Thus, KEPCo is in immediate need of improvement in its financial condition.

In addition, while it has been improving, KEPCo still has an extremely weak balance sheet. It has never accumulated very much equity capital and, when calculated on the basis of GAAP, its equity capital has for many years been negative and remains negative currently. KEPCo's equity to assets ratio struck bottom at a negative 29.5% in 2001 just before its last rate change. Since then its equity to assets ratio has steadily improved and is projected to be a negative 5.5% at the end of 2007. In light of this fact and the increasingly changing and risky environment in which KEPCo operates, it is important that KEPCo demonstrate its commitment to continuing its adherence to its long-term financial plan that is designed to restore its financial health and improve its balance sheet and its ability to withstand future financial shocks. Hopefully, with the use of the 1.2 DSC as I am recommending and the addition of the proposed demand-related PPCA, KEPCo will be able to attain its 20% equity ratio target in the next five or six years.

Additionally, KEPCo faces near-term and longer term challenges that will require tangible demonstration of KEPCo's commitment to developing and maintaining its long-term financial soundness. As new and replacement power supply resources are required in the next several years, KEPCo will increasingly be required to demonstrate its credit worthiness to wholesale power suppliers and to lenders, as well as to its transmission services provider. Since the majority by far of KEPCo's costs arise from its acquisition of generation resources, it needs the financial flexibility to make the most economic choices in its power supply acquisitions. This means the ability to choose the most economical purchased power resources or to build generating facilities of its own. In order to have such financial flexibility, KEPCo needs to demonstrate its long-term financial soundness and where with all to weather short-term financial shocks. A major part of that is accumulating equity capital and substantially improving its equity ratio. Of course, as a member-owned cooperative, KEPCo's equity capital must be collected from its Members through its rates.

Q. How do your recommended DSC, TIER and equity as a percent of asset ratios of 1.2, 1.2 and 20% respectively compare with those of KEPCo's electric utility peers?

A. I will not repeat them here, but Table 3, on page 23, of my report in Section 14 shows TIER ratios of KEPCo and its peers and Table 5, on page 26, shows comparative equity ratios. I wasn't able to compile a comparable comparison of DSC ratios because DSC ratios are not publicly reported for G&Ts as TIERs and equity ratios are. However, DSC ratios and TIERs are usually reasonably close except in instances such as KEPCo now faces where its loan principal payments are becoming significantly different than its depreciation and amortization expenses. Table 3 shows that KEPCo's TIERs generally have been below those of its G&T cooperative peer groups, and they have not been consistent over time. As would be expected, KEPCo's members have experienced much higher TIER ratios than KEPCo. Over the periods of 1998-99 and 2004-05, the TIERs experienced by those RUS borrower G&T electric cooperatives with positive equity ratios reported by the RUS was 1.74. During the same period, the average TIER experienced by KEPCo's distribution cooperative Members was higher. KEPCo's own average for the same years was 1.29. Thus, a TIER target of 1.2 is very reasonable, if not conservative, when compared to those being earned by KEPCo's peers.

While the TIER is an interest coverage ratio ((margin + interest)/interest), the DSC is a total debt service coverage ratio ((margin + interest + depreciation)/(principal + interest)) that is influenced by the extent to which there is a significant difference between depreciation expense and loan principal payments. Since DSC ratios are generally expected to be near the TIERs, 1.2 is also a reasonable DSC target for KEPCo rate setting purposes. However, due to KEPCo's current circumstances where principal payments are substantially higher than its depreciation (and amortization) expenses, it is the DSC that will be the necessary driver of KEPCo's margin requirements for rate setting purposes and will be the more important financial indicator for KEPCo for some time to come. As also demonstrated above, it is the DSC which is currently the most critically in need of repair in order to avoid default under KEPCo's mortgage.

Similarly, my recommended long-term goal of 20% equity to total assets ratio compares favorably with those experienced by KEPCo's peers. The 1998-99 and 2004-05 average equity-to-assets ratio for all G&Ts with positive equity was 23.7% and was 44.1% for KEPCo's distribution Members. By comparison, the average common equity (to total capital) ratios of integrated investor-owned electric utilities was 43%.

Q. If KEPCo's RUS/CFC mortgage requirement is a DSC of 1.0, why should KEPCo be allowed to establish rates based on a target ratio of 1.2?

A. In addition to the major reasons I discuss above for KEPCo's use of a 1.2 DSC and the other reasons I discussed in my report in Section 14, it should be recognized that the 1.0 is a bare minimum in order to avoid default under the mortgage. Obviously, conditions in the electric utility industry are fluid and the conditions reflected in developing the test-year revenue requirement for ratemaking purposes are sure to change. Such changes may cause the earned DSC (and TIER) to be more or less than that incorporated in rates. Therefore, in order to assure that the minimum default DSC of 1.0 is actually achieved in practice, the test year target DSC should be set at something higher. In addition, the 1.0 default requirement essentially assumes a stable environment where the utility's equity ratio is already substantial and that there is virtually no growth in assets. The assumption of reasonably significant equity to asset ratios are assumed in the mortgage in that Section 4.16 of the mortgage provides that unless written waiver is granted, unrestricted capital credit payments are not allowed unless KEPCo's equity as a percent of assets is 30% or more. It also provides that if the equity ratio is in the 20%-29% range, KEPCo may retire capital credits up to 25% of the prior year's net margin. If it is less than 20%, a written waiver must be obtained for any capital credit retirements at all. Thus, the basic expectation reflected in the mortgage is that no capital credit payments will be made back to members until the 20% equity to asset ratio threshold is attained. Clearly, KEPCo's equity ratio is far below the 20% threshold and it needs to be substantially improved. The only way to achieve increases in the equity ratio for KEPCo as a cooperative enterprise, is for it to earn positive margins which produce DSC and TIER ratios greater than 1.0. In addition, if the cooperative's assets are growing, positive margins producing DSC and TIER ratios greater than 1.0 must be earned simply to maintain the existing equity ratio. Therefore, given KEPCo's need to rebuild its severely depleted cash balances and to significantly improve its equity ratio over time, a DSC (and TIER) significantly above the 1.0 mortgage default level must be attained.

Q. I have no further questions at this time.

J. BERTRAM SOLOMON
PRIOR RATEMAKING TESTIMONY
AND
OTHER PUBLICATIONS

TESTIMONY

FEDERAL ENERGY REGULATORY COMMISSION

Allegheny Electric Cooperative, Inc., Docket No. EL00-88-000

Allegheny Power, Docket No. ER02-136-004

Alliance Companies, *et al.*, Docket Nos. ER99-3144-000 and EC99-80-000

American Electric Power Service Corporation, Docket No. ER93-540-000

Appalachian Power Company, Docket Nos. ER87-105-002, ER87-106-002, EL89-53-000, ER90-132-000, ER90-133-000, & ER92-323-000

Arizona Public Service Company, Docket Nos. ER81-179 & ER82-481

Blue Ridge Power Agency, et al., Docket No. EL89-53-000

Boston Edison Company, Docket Nos. ER93-150-000 & EL93-10-000

North Carolina Electric Membership Corporation vs. Carolina Power & Light Company, Docket No. EL91-28-000

Carolina Power & Light Company, Docket Nos. ER76-495, ER77-485 & ER80-344

Central Hudson Gas & Electric Corp., et al., Docket Nos. ER97-1523-011, et al.

Central Louisiana Electric Company, Docket No. ER82-704

Central Montana Electric Power Cooperative, Inc. v. Montana Power Co., Docket No. EL99-24-000

Cleveland Electric Illuminating Co. and Toledo Edison Co., Docket Nos. OA96-204-000, et al.

Delmarva Power and Light Company, Docket Nos. ER93-96-000 & EL93-11-000

Duke Power Company, Docket Nos. FA83-4-001 & ER89-106-000

East Texas Electric Cooperative, Inc., Docket No. ER94-891

Entergy Services, Inc., Docket No. ER95-112-000, et al.

Florida Power & Light Company, Docket No. ER86-383-001; ER93-465-000, et al.; ER99-2770-000

Georgia Power Company, Docket Nos. E-9091, E-9521, ER76-587, ER78-166 & ER79-88, ER85-659 & ER85-660

Golden Spread Electric Cooperative, Inc., et al., Docket No. EL05-19-000, et al.

Gulf States Utilities Company, Docket Nos. ER84-568-000 & ER85-538-001

Idaho Power Company, Docket No. ER06-787-002

IES Utilities, Inc., Interstate Power Co., Wisconsin Power & Light Co., South Beloit Water, Gas & Electric Co., Heartland Energy Services and Industrial Energy Applications, Inc., Docket Nos. EC96-13-000, ER96-1236-000 and ER96-2560-000

Indiana & Michigan Electric Company, Docket Nos. ER78-379, et al.

Kansas Gas & Electric Company, Docket Nos. ER77-578 & ER82-412

Kentucky Utilities Company, Docket No. ER82-673

Louisiana Power & Light Company, Docket Nos. ER77-533, ER81-457 & EL81-13 & FA86-063-001

Maine Yankee Atomic Power Company, Docket No. EL93-22-000

MISO, Docket No. ER05-6, et al.

Midwest Independent Transmission System Operator, Inc., Docket No. ER02-485-000

Montana Power Company, Docket No. ER98-2382

Nantahala Power & Light Company, Docket Nos. ER76-828 & EL78-18

New Dominion Energy Cooperative, Old Dominion Electric Cooperative, Docket Nos. ER05-18-002 and ER05-309-002

New York State Electric & Gas Corporation, Docket No. ER82-803

Niagara Mohawk Power Corporation, Docket No. ER86-354-001

North Carolina Electric Membership Corporation v. Virginia Electric & Power Company, Docket No. EL90-26-000

Oglethorpe Power Corporation, Docket No. EL85-40

Ohio Edison Company, *et al.*, Docket Nos. ER97-412-000 and ER97-413-000

Old Dominion Electric Cooperative, Inc., Docket No. ER07-1134-000

Pennsylvania Power & Light, Inc., Docket No. ER00-1014-000

PJM Interconnection, L.L.C., Docket No. EL05-121

PJM Interconnection, LLC, Docket No. ER01-1201-000

Portland Natural Gas Transmission System, Docket No. RP02-13-000

Potomac Edison Company, Docket No. ER95-39-000

PSI Energy, Inc., Docket No. ER00-188-000

Public Service Company of Indiana, Docket No. ER76-149

Public Service Electric & Gas Company, *et al.*, Docket Nos. EC99-79-000 and ER99-3151-000

Southern Company Services, Inc., Docket Nos. ER98-1096-000, et al.

Southwestern Public Service Company, Docket No. ER06-274-003

Virginia Electric & Power Company, Docket No. ER84-355-000

Western Resources, Inc., Docket Nos. ER95-1515 and ER96-459-000

ALASKA REGULATORY COMMISSION

In the Matter of the Tariff Revision, Designated as TA226-8, filed by Chugach Electric Association, Inc. for a Rate Increase and Rate Design, Docket No. U-01-108

ARKANSAS PUBLIC SERVICE COMMISSION

Arkansas Electric Cooperative Corporation, Docket Nos.93-132-U & 93-134-P

In the Matter of the Application of Entergy Arkansas, Inc. for Approval of Changes in Rates for Retail Electric Service, Docket No. 96-360-U

In the Matter of the Motion of the General Staff of the Arkansas Public Service Commission to Establish a Docket to Determine the Reasonableness of the Rates of Southwestern Electric Power Company, Docket No. 98-339-U

In the Matter of the Unbundling of the Rates of Arkansas Electric Cooperative Corporation, Docket No. 99-251-U

FLORIDA PUBLIC SERVICE COMMISSION

Tampa Electric Company, Docket No. 850050-EI

GEORGIA PUBLIC SERVICE COMMISSION

Georgia Power Company, Docket Nos. 3840-U, 4133-U and 4136-U

IN THE CIRCUIT COURT OF THE ELEVENTH JUDICIAL DISTRICT McLEAN COUNTY, ILLINOIS

Corn Belt Energy Corp. vs. Illinois Power Co., Case No. 2001 L 195

PUBLIC SERVICE COMMISSION OF INDIANA
(Now Indiana Utility Regulatory Commission)

Public Service Company of Indiana, Cause No. 37414

STATE CORPORATION COMMISSION OF THE STATE OF KANSAS

Kansas Electric Power Cooperative, Inc., Docket No. 01-KEPE-1106-RTS

KENTUCKY PUBLIC SERVICE COMMISSION

Big Rivers Electric Corporation, Case Nos. 6499, 9006 & 9163

Fern Lake Company, Case Nos. 6971, 7292, 7982 & 8276

Jackson Purchase Electric Cooperative Corporation, Case No. 6992

MAINE PUBLIC UTILITIES COMMISSION

Maine Public Service Company, Docket Nos. 84-80 & 84-113

MICHIGAN PUBLIC SERVICE COMMISSION

Detroit Edison Company, Case No. U-7660

PUBLIC UTILITIES COMMISSION OF MINNESOTA

Northern States Power Company, E-002/GR-91-1 & OAH 7-2500-5291-2

NEVADA PUBLIC UTILITIES COMMISSION

Sierra Pacific Power Company, PUCN 01-11030

NEW JERSEY BOARD OF PUBLIC UTILITIES

Jersey Central Power & Light Company, ER 89110912J, EM 91010067 & OAL 1804-91

NORTH CAROLINA UTILITIES COMMISSION

Duke Power Company, Docket No. E-7, SUB 487

Nantahala Power & Light Company, Docket Nos. E-13 SUB 29 Remand, E-13 SUB 35, & E-13 Sub 44

North Carolina Electric Membership Corporation, Docket No. E-100 SUB 58

North Carolina Natural Gas Corporation, Docket Nos. G-21, SUB 306 and G-21, SUB 307

Piedmont Natural Gas Company, Inc., Docket Nos. G-9, SUB 300, Remand; G-9, SUB 306, Remand; G-9, SUB 308, Remand

In The Matter Of Dominion North Carolina Power Investigation Of Existing Rates And Charges, Docket No. E-22, SUB 412

CP&L Energy, Inc. and Florida Progress Corp., Docket No. E-2, SUB 760

PUBLIC UTILITY COMMISSION OF OHIO

FirstEnergy Corporation, *et al.*, Case Nos. 99-1212-EL-ETP, 99-1213-EL-ATA, and 99-1214-EL-AAM

In The Matter Of The Application Of The Cincinnati Gas & Electric Company For Approval Of Its Transition Plan And For Authorization To Collect Transition Revenues, *et al.*, Case Nos. 99-1658-EL-ETP, 99-1659-EL-ATA, 99-1660-EL-ATA, 99-1661-EL-AAM, 99-1662-EL-AAM, and 99-1663-EL-UNC

Columbus Southern Power Co., *et al.*, Case Nos. 99-1729-EL-ETP and 99-1730-EL-ETP

In The Matter Of The Application Of The Dayton Power & Light Company For Approval Of Their Transition Plan Pursuant To Section 4928.31, Revised Code And For Opportunity To Receive Transition Revenues As Authorized Under Sections 4928.31 To 4928.40, Revised Code; Case Nos. 99-1687-EL-ETP and 99-1688-EL-AAM

In the Matter of the Continuation of the Rate Freeze and Extension of the Market Development Period for the Monongahela Power Company, Case No. 04-880-EL-UNC

In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company for Authority to Recover Costs Associated with the Construction and Ultimate Operation of an Integrated Gasification Combined Cycle Electric Generating Facility, Case No. 05-376-EL-UNC

CORPORATION COMMISSION OF THE STATE OF OKLAHOMA

Application Of Ernest G. Johnson, Director Of The Public Utility Division, Oklahoma Corporation Commission To Review The Rates, Charges, Services, And Service Terms Of Oklahoma Gas And Electric Company And All Affiliated Companies And Any Affiliate Or Nonaffiliate Transaction Relevant To Such Inquiry, Cause No. PUD 200100455

In The Matter Of The Application Of Oklahoma Gas And Electric Company For An Order Of The Commission Authorizing Applicant To Modify Its Rates, Charges, And Tariffs For Retail Electric Service In Oklahoma, Cause No. PUD 200500151

PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Electric Company, Docket Nos. R-842771, R-860413, M-870172C003 & R-880979

PUBLIC UTILITIES COMMISSION OF THE STATE OF RHODE ISLAND AND PROVIDENCE PLANTATIONS

Narragansett Electric Company, Docket No. 2019

PUBLIC SERVICE COMMISSION OF SOUTH CAROLINA

In the Matter of South Carolina Electric And Gas Company's Annual Review of Base Rates for Fuel Costs, Docket No. 2005-2-E

PUBLIC UTILITY COMMISSION OF TEXAS

Gulf States Utilities Company, Docket Nos. 4510, 5108, 5560 & 5820

Lower Colorado River Authority, Docket Nos. 8032, 8400 & 9427

Sam Rayburn G&T, Inc., Docket Nos. 5657, 6440, 6797, 7991 & 8595

Southwestern Electric Service Company, Docket Nos. 5044 & 6610

Texas Electric Service Company, et. al., Docket No. 4224

Texas Electric Service Company, Docket No. 5200

Texas Power & Light Company, Docket Nos. 1517, 1517 (On Remand), 3006, 3780 & 4321

Texas Utilities Electric Company, Docket No. 5640, 11735, 15195

Tex-La Electric Cooperative of Texas, Inc., Docket No. 7279

Tex-La Electric Cooperative of Texas, Inc., Sam Rayburn G&T Electric Cooperative, Inc., and Northeast Texas Electric Cooperative, Inc., Docket No. 13100

Application of TXU Electric Company for Financing Order to Securitize Regulatory Assets and Other Qualified Costs, Docket No. 21527

Application of TXU Electric Company for Approval of Unbundled Cost of Service Rate Pursuant to PURA § 39.201 and Public Utility Commission Substantive Rule § 25.344, PUC Docket No. 22350

Generic Issues Associated with Applications for Approval of Unbundled Cost of Service Rate Pursuant to PURA § 39.201 and Public Utility Commission Substantive Rule § 25.344, PUC Docket No. 22344

Application of Central Power & Light Company for Approval of Unbundled Cost of Service Rates Pursuant to PURA § 39.201 and PUC Substantive Rule § 25.344, PUC Docket No. 22352

Application of West Texas Utilities Company for Approval of Unbundled Cost of Service Rates Pursuant to PURA § 39.201 and PUC Substantive Rule § 25.344, PUC Docket No. 22354

Application Of LCRA Transmission Services Corporation To Change Rates, SOAH Docket No. 473-04-1662, PUC Docket No. 28906

Application of CenterPoint Energy Houston Electric LLC, For a Competition Transition Charge (CTC), PUC Docket No. 30706

Complaint of Kenneth D. Williams Against Houston Lighting & Power Co., Docket No. 12065

VIRGINIA STATE CORPORATION COMMISSION

Appalachian Power Company, Case No. PUE900026

Old Dominion Power Company, Case Nos. 20106, PUE800028, PUE810074, PUE830035 & PUE830069

Application of Virginia Electric and Power Company for Approval of Alternative Regulatory Plan, Case No. PUE960296

DEPOSITIONS

IN THE CIRCUIT COURT OF THE ELEVENTH JUDICIAL DISTRICT McLEAN COUNTY, ILLINOIS

Corn Belt Energy Corp. vs. Illinois Power Co., Case No. 2001 L 195, July 9, 2003

PUBLIC UTILITY COMMISSION OF TEXAS

Application of CenterPoint Energy Houston Electric LLC, For a Competition Transition Charge (CTC), PUC Docket No. 30706, March 16, 2005

EXPERT REPORTS

Corn Belt Energy Corporation v. Illinois Power Co., Report Of Findings And Conclusions Regarding Illinois Power Company Network Transmission Service And Power Supply Cost Damages Suffered By Corn Belt, May 2, 2003

Old Dominion Electric Cooperative v. Ragnar Benson, Inc., Expert Report Of J. Bertram Solomon On Review Of Expert Report Of William J. Kemp, Civil Action No. 05-CV-34

PRESENTATIONS

Future Power Supply: Contracts vs. Ownership, National Rural Electric Association Power Supply Conference, November 2002

CERTIFICATION

I, J. Michael Peters, do hereby certify that I am the duly appointed and qualified Assistant Secretary of Kansas Electric Power Cooperative, Inc. and that the following is a true and correct copy of the Resolution duly adopted by the Board of Trustees of Kansas Electric Power Cooperative, Inc. at its Board of Trustees Meeting held August 15, 2007:

RESOLUTION NO. 07-21

ADOPTING THE 2007 KEPCo FINANCIAL PLAN

WHEREAS, a financial plan for KEPCo entitled 2007 Financial Plan and Analysis of Margin Requirements (2007 Financial Plan) has been presented to the Board; and

WHEREAS, the financial policies and recommendations contained in the 2007 Financial Plan are in the best interests of KEPCo and should be adopted as guidance in KEPCo's ratemaking activities;

NOW, THEREFORE, BE IT RESOLVED that the 2007 Financial Plan as presented to the Board is hereby adopted.

And that the action taken and Resolution adopted as above set out has never been rescinded, altered, amended, modified or repealed, and is on this date in full force and effect.

IN WITNESS WHEREOF, I hereby set my hand and attached the seal of the Corporation this 21st day of December, 2007.

KANSAS ELECTRIC POWER COOPERATIVE, INC.
CORPORATE SEAL
KANSAS

J. Michael Peters, Assistant Secretary