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Witness: Robert J. Camfield
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MISSOURI PUBLIC SERVICE COMMISSION

CASE NO. ER-2006-____

DIRECT TESTIMONY

OF

ROBERT J. CAMFIELD

ON BEHALF OF

KANSAS CITY POWER & LIGHT COMPANY

**Jefferson City, Missouri
January 2006**

**DIRECT TESTIMONY OF
ROBERT J. CAMFIELD**

BEFORE THE MISSOURI PUBLIC SERVICE COMMISSION

**REGARDING THE PETITION OF
KANSAS CITY POWER AND LIGHT COMPANY
TO INCREASE RATES FOR RETAIL ELECTRICITY SERVICE**

DOCKET NO: XXXXX

1 **Q. Please state your name, title, and business address.**

2 A. My name is Robert J. Camfield. I am a Vice President with Christensen
3 Associates Energy Consulting LLC. My business address is Suite 700, 4610
4 University Avenue, Madison, Wisconsin, 53705.

5

6 **Q. What is the scope of your testimony?**

7 A. Kansas City Power and Light Company has retained Christensen Associates
8 Energy Consulting (CA Energy Consulting) to assess its utility performance,
9 and to report the findings of the performance study in the immediate docket.
10 My testimony is focused on the performance of Kansas City Power and Light
11 Company in providing electric service to retail consumers over recent years.
12 The testimony and accompanying exhibits review and summarize our study of
13 KCPL's performance for the consideration of the Missouri Public Service
14 Commission. The testimony goes on to discuss the evolution and status of
15 wholesale power markets and, associated with wholesale markets, the
16 underlying causes of higher capital risks inherent to the electricity industry. The
17 testimony concludes with recommendations regarding the incorporation of
18 performance in the rate of return, within the current docket.

1 **Q. What guidelines regarding the scope, approach, technical methodology,**
2 **and criteria did Kansas City Power and Light provide to CA Energy**
3 **Consulting, for assessment and study of the Company's performance?**

4 A. None, the study was performed with complete independence. All aspects of the
5 study including scope, approach, criteria, and selection of peer groups of
6 electric utilities were determined at the discretion of CA Energy Consulting.

7

8 **Q. Please review your professional background and experience that qualifies**
9 **you to provide such recommendations.**

10 A. My experience covers a number of issues facing regulated industries. I have
11 represented agency staff, consumer advocates, independent energy companies,
12 utilities, and transmission companies before a number of regulatory agencies
13 regarding issues of cost of capital, cost performance and benchmarking,
14 forecasts of electricity demand, retail tariffs, cost of service allocation,
15 generation planning, and transmission congestion. I have been involved in the
16 negotiation of power supply contracts and the terms for franchise licenses. My
17 overseas assignments are several including a comprehensive market
18 restructuring plan in Central Europe. I have served on national and regional
19 advisory panels, and I have advised electric companies on numerous policy and
20 technical issues. Innovations include two-part tariffs for transmission services,
21 web-based self-designing retail electric products, marginal cost-based cost-of-
22 service methods, and efficient pricing of distribution services. I have published
23 articles in *The Electricity Journal*, *IEEE Transactions on Power Systems*, and
24 *CIGRE*. Currently, I am the Program Director of EEI's Transmission and
25 Market Design School.

1 I joined the Michigan Public Service Commission in 1976 as staff economist.
2 My tenure with the Michigan Commission involved retail electricity and natural
3 gas pricing issues, and I testified in several regulatory proceedings cost of
4 capital and retail gas prices. I joined the New Hampshire Public Service
5 Commission in 1979 as senior economist, and held the position of chief
6 economist beginning in 1981. In these capacities, I was responsible for the
7 development, administration, and training of the economics staff. I oversaw
8 economic analysis and the development and delivery of testimony, and provided
9 policy advice to the Commission on a variety issues such as construction work
10 in progress, financial planning, and the determination of PURPA Section 133
11 rates. I joined Southern Company in 1983, and held positions in several
12 departments including Pricing and Economic Analysis at Georgia Power
13 Company, Costing Analysis of Southern Company Services, and Southern
14 Company's Strategic Planning Group. In 1994, I joined Laurits R. Christensen
15 Associates, Inc. as senior economist, and currently hold the position of Vice
16 President.

17

18 I am a graduate of Interlochen Arts Academy, and hold a Bachelor of Science
19 Degree in Business Administration from Ferris State University with an
20 emphasis in Management, graduating in 1969. I earned a Master of Arts Degree
21 in Economics at Western Michigan University in 1975, with a concentration in
22 Monetary Theory and Policy.

1 **Q. Can you briefly review the market context of Kansas City Power and Light**
2 **Company?**

3 A. Yes. Kansas City Power and Light Company (KCPL) is a wholly owned
4 subsidiary of Great Plains Energy Inc and provides electricity service in Kansas
5 City, Missouri and the surrounding region. KCPL's service territory covers
6 metropolitan areas, small cities and communities, and rural areas with
7 concentrations of residential and small to mid-sized commercial and industrial
8 customers, along with some large customers. In addition, KCPL is involved in
9 the wholesale power markets of the Midwest region on a substantial scale with
10 relatively high concentrations of short- and intermediate-term transactions.

11

12 **Q. You mention integrated service. What is the nature of KCPL's integrated**
13 **electricity service and what are the resources employed by KCPL to**
14 **provide it?**

15 A. Integrated service refers to the package of generation, transmission, distribution,
16 and customer service activities as a bundled retail utility service. The resources
17 used to provide integrated service include capital, labor, material and service
18 inputs, along with primary and nuclear fuel. Capital resources are unusually
19 large scale, very long lived, and highly specialized. The scale of the facilities is
20 necessary in order to obtain comparatively low supply costs through economies
21 of scale. Generation service refers to the production or generation of electric
22 energy and capacity to provide reserve services in the form of regulation, spin,
23 and supplemental reserve categories. Transmission and distribution service
24 (delivery) is the transport of power from KCPL's generation plants where

1 electricity is produced to customer facilities and premises where it is consumed.
2 Distribution also includes connection services involving voltage transformation
3 and meters. The provision of integrated service also includes customer service
4 and sales involves meter reading (metering), bill rendering, the process of
5 responding to customer inquiries regarding electricity service and bills, and the
6 process of assisting customers in the efficient use of energy and tariff choices.

7
8 KCPL is an established organization, and on-going integrated service on the
9 scale of KCPL involves substantial resource inputs that are closely coordinated
10 operations. Electricity cannot be stored, and the flow of electricity within
11 electrical circuits, the service itself, is governed by physical laws. This means
12 that the operation of the resources and facilities involved in the production and
13 delivery of electricity must adhere to a strict regiment and protocol in order for
14 electricity to be provided reliably to retail consumers. This involves the
15 monitoring and control of power systems across the integrated system in order
16 to achieve an exact balance of supply with consumer demand in real time. Real-
17 time balance involves load following and occasional redispatch to manage
18 congestion, using a combination of reserve services as provided by committed
19 and non-committed units.

20
21 To provide generation services, KCPL has invested in and operates a sizable
22 fleet of nuclear, coal, and natural gas generating units. Generating units are
23 large facilities with specialized equipment as mentioned, including fuel storage
24 and fuel handling facilities, boilers and pressurized steam generators, turbines,
25 cooling towers and condensers, electric generators and exciters, transformers,

1 and black start ancillary generators. Generation is carried out in accordance
2 with least-cost principles that apply to long-term planning, fuel purchasing,
3 maintenance scheduling, unit commitment, and dispatch activities. In addition,
4 these units must operate in a manner that complies with safety and
5 environmental regulations.

6
7 Transmission consists of high voltage transport facilities configured as meshed
8 and radial circuits. Facilities include towers, conductors, insulators,
9 transformers, substations, and various devices to control voltage and to ensure
10 adequacy of reactive power. Transmission also includes monitoring and control
11 technologies and activities. Because KCPL is a designated control area, it must
12 adhere to the reliability guidelines of the North American Electric Reliability
13 Council (NERC). Electric distribution is linked to transmission networks.

14 Distribution service provided by KCPL involves investment in and the
15 operation and maintenance (O&M) of distribution facilities including wires
16 (lines, poles, substations and equipment) and connections (customer
17 transformer, meters). Distribution facilities include underground and overhead
18 transformers and conductors organized as radial and loop circuits operated at a
19 variety of voltages, as well as right-of-way, towers, underground conduits,
20 substation transformers, customer transformers, and compensation technologies
21 including capacitors and reactors. Facilities also include circuit switch gear and
22 monitoring and control technologies (SCADA) that help maintain power service
23 and expedite service restoration in the case of an occasional reliability failure or
24 storm event.

1 In summary, integrated electric service, including the resources employed in the
2 course of providing it, is complex and is not to be taken lightly. Indeed, electric
3 utilities like Kansas City Power and Light must harness, organize, and utilize to
4 the fullest the specialized knowledge, skills, and capabilities of its staff in order
5 for integrated electric services, ever so vital to regional economies, to work. As
6 I will demonstrate, Kansas City Power and Light has achieved a high standard
7 of performance, and in terms of productivity, has obtained very high levels.

8

9 **Q. Please describe the input costs associated with providing integrated**
10 **electricity services.**

11 A. Costs of integrated service include operations and maintenance expenses and
12 the charges on capital investment, including the physical facilities (capital
13 stock), inventory, and working capital. As mentioned, the physical facilities
14 associated with electricity services require capital investment on a large scale
15 due to the sheer size of the specialized equipment employed in providing
16 services. Also, the investment levels needed to satisfy on-going growth in
17 regional economic activity are rather indivisible and lumpy, a characteristic
18 which requires special diligence and caution as regards to the management of
19 capital risks.

20

21 **Q. What is the general approach used in the study to gauge the performance**
22 **of KCPL and the integrated services that it provides?**

23 A. At the outset, an assessment of performance faces three fundamental study
24 design issues including: 1) the perspective from which performance should be
25 gauged; 2) the metrics that align with the identified perspective; and 3) the

1 criteria that should be used to gauge relative performance for the defined
2 metrics. For the immediate study, performance is gauged from the perspective
3 of retail consumers and markets. In essence, the study addresses the question,
4 “what has been the performance of KCPL in providing integrated electricity
5 services over recent years, from the perspective of retail consumers?”

6
7 The study assesses the performance of KCPL in terms of *Performance Level*,
8 where the performance of KCPL is measured within specific timeframes, and
9 *Performance Trend* where KCPL’s performance is measured over time. For
10 several metrics, KCPL’s performance is measured (benchmarked) with respect
11 to samples of comparable electric utilities. The trend in performance, as
12 measured by rates of change over time, is the most meaningful measure because
13 it reflects the effectiveness of service providers in obtaining on-going
14 improvement in operations and productivity.

15

16 **Q. Please identify the metrics used in the study to assess performance.**

17 A. For the immediate study, which is geared to assessing KCPL’s performance
18 from the perspective of retail markets, the following categories of metrics have
19 been selected:

- 20 • Overall Retail Prices refers to the level and general trend over recent years
21 of the all-in prices paid by retail consumers for the bundled electricity
22 services provided by KCPL.
- 23 • Total Factor Productivity (TFP) refers to the level and trends in resource
24 inputs used in providing outputs. The outputs of integrated services
25 provided to retail markets can assume several attributes such as the

1 number of customers, the level of energy (MWhs), and territorial peak
2 demand (MWs).

3 • Cost Diagnostics refers to unit-specific or normalized costs, where
4 operations costs are gauged with reference to 1) capital inputs, and 2)
5 aspects of the output such as retail electricity sales (MWh), number of
6 retail customers, and peak demand.

7 • Scorecard Metrics refers to selected elements of the *Balanced Scorecard*,
8 which is the internal self-appraisal process implemented by KCPL in
9 recent years.

10 For the performance categories *Overall Retail Prices*, *Total Factor Productivity*,
11 and *Cost Diagnostics*, the assessment is conducted over the 1994 – 2004
12 timeframe, which is broken into the periods 1994 – 1998 and 1999 – 2004.
13 Generally speaking, greater emphasis is given to the more recent five years, and
14 trends rather than levels, because year-over-year changes are more suggestive of
15 the success of the actions, plans, and activities of utilities to improve
16 performance. Essentially, improvement is reflected in unit-of-output cost
17 changes across years. Total factor productivity captures the efficiency of
18 resource utilization and is arguably the most meaningful gauge of overall
19 performance for electric service providers. The Balanced Scorecard, on the
20 other hand has only recently been put in place and thus cannot reflect upon the
21 experience over longer timeframes.

1 **Q. You mention Kansas City Power and Light's Balanced Corporate**
2 **Scorecard as an internal performance assessment mechanism. Please**
3 **describe.**

4 A. At the initiative of its Board of Directors, Kansas City Power and Light has
5 implemented an internal process of on-going performance appraisal referred as
6 the Corporate Scorecard. KCPL's Scorecard provides a separate assessment of
7 each of the four major areas of integrated electric service including generation
8 (supply), transmission, distribution, and customer services. Several Scorecard
9 metrics are used in our independent study of the overall performance by KCPL.
10 These metrics are the *Customer Satisfaction Index*, the *SAIDI Index of*
11 *Reliability*, the *% of Customers Returned to Service Within 2 Hours*, and
12 *Customer Service and Call Speed of Response*.

13
14 The Scorecard system is comprehensive and, for each of the service areas,
15 KCPL's Scorecard includes a battery of metrics relevant to the specific area.
16 For generation services, KCPL's Scorecard recognizes 17 metrics; transmission
17 recognizes 12 metrics, distribution covers 23 metrics, and customer service
18 metrics include 30 separately defined elements. The metrics are grouped into
19 categories referred to as Customer, Financial, Internal, and a corporate category
20 referred to as Learning and Innovation which includes safety. Some of the
21 metrics are direct measures of the attributes of electric services delivered to
22 customers such as the System Average Interruption Duration Index (SAIDI) and
23 the national survey of customer satisfaction. Others are on-going performance
24 indicators aimed at the internal processes of the various organizations and areas
25 that together provide integrated electric service to customers. Example

1 indicators of process performance include direct operations and maintenance
2 expenditure per customer (a financial indicator for distribution operations); line
3 clearance miles completed on schedule (an internal indicator for distribution
4 operations); OSHA incidence rate (a corporate category indicator for generation
5 services); and CellNet monthly read percentage (a financial indicator for
6 customer services).

7
8 Many of the metrics are measured and reported monthly, although some are
9 only relevant on an annual basis. For some metrics, KCPL assesses or
10 benchmarks its performance with reference to industry-wide experience, while
11 other metrics gauge performance over time and with reference to stated levels,
12 goals, and targets. For many of the individual metrics of the various service
13 areas, the Scorecard references specific programs, action plans, and strategies
14 that have been or are intended to be implemented by KCPL to improve
15 performance, as gauged by the individual metrics.

16

17 **Q. Please continue in the description of the metrics, first focusing on Retail**
18 **Electricity Prices.**

19 A. *Overall retail electricity prices*, sometimes called all-in prices, are determined
20 as the sum of the annual retail revenues across the various market segments and
21 customer classes served, divided by the sum of retail electricity consumption,
22 also across segments and classes. Overall retail prices are measured in nominal
23 terms. The retail price metric does not and for the purpose at hand should not
24 delve into the relative prices of individual tariff elements and cost-of-service
25 among market segments. Attempting to assess the prices of KCPL at a tariff

1 level raises complicated and not easily resolved problems of comparability
2 among utilities including differences in: 1) criteria to qualify for service
3 provided under individual retail tariffs; 2) energy and demand price blocks
4 within tariffs; and 3) principles underlying how individual tariff prices are
5 determined. In addition, customer composition is a determining factor; utilities
6 with larger shares of residential and commercial customers will generally have
7 higher prices than utilities with a high share of industrial load in the total mix of
8 customers.

9
10 Total Factor Productivity (TFP) is a measure of the efficiency with which
11 integrated electricity services are provided. Essentially, TFP addresses the
12 question, “How well is a utility using its resources?” TFP is determined for
13 each of the unbundled services including generation, transmission, distribution,
14 and customer service, and for integrated service as a whole. In turn, generation
15 involves the several generation segments including fossil steam, nuclear, hydro
16 including conventional, run-of-river, and pumped storage, fossil non-steam
17 generation, and purchased power. Customer service includes metering and
18 billing, customer service, and sales.

19
20 For each of the four elements of integrated electricity service, including the
21 individual generation technology classes, the implied physical quantities of
22 inputs of capital, labor, fuels, and quasi-materials (other inputs) are estimated.
23 Estimates of TFP involve the aggregation of inputs and outputs for utilities and
24 for comparable utilities. The methodology to determine TFP is more fully
25 described in the technical discussion paper, as attached.

1 Cost Diagnostics refers to cost categories normalized according to other inputs
2 such as estimates of the capital stock, and to levels of the services provided
3 (MWh), MWs of peak demand, number of customers served). The specific cost
4 diagnostics incorporated into our study of performance are as follows:

- 5 • Generation Services:
 - 6 ○ Real capital stock, per unit of energy supplied (MWhs).
 - 7 ○ O&M expenses, per unit of investment in generation facilities.
- 8 • Transmission Service:
 - 9 ○ Real capital stock, per unit of peak demand (MWs).
 - 10 ○ O&M expenses, per unit of investment in transmission
11 facilities.
- 12 • Distribution Service:
 - 13 ○ Real capital stock, per unit of peak demand.
 - 14 ○ Real capital stock, per customer served.
 - 15 ○ O&M expenses, per unit of investment in distribution facilities.
- 16 • Customer Services:
 - 17 ○ O&M expenses, per customer served.

18
19 Scorecard Metrics incorporated into the study of KCPL's performance include
20 the results of the J. D. Power national survey of *Customer Satisfaction*;
21 delivered service reliability measured as the *System Average Interruption*
22 *Duration Index* (SAIDI); and customer service measured as the expedience with
23 which incoming customer inquiries are answered by KCPL. The SAIDI
24 measure of reliability is equal to the total interruption time of power outages
25 divided by the average number of customers served.

1 **Q. You have mentioned that, for the defined metrics, the assessment process**
2 **involves criteria to gauge relative performance. Please discuss.**

3 A. The performance assessment utilizes the identified metrics. As mentioned, the
4 metrics should be relevant to and align with the perspective of the identified
5 stakeholders—retail consumers for the immediate study. However, there is no
6 completely objective basis to rate or gauge performance. For this reason, the
7 study of the performance of KCPL is assessed with reference to the
8 performance of other utilities. That is, the performance of the comparable
9 utilities provides the basis to gauge the performance of KCPL.

10

11 **Q. For the comparison utility metrics how is the group of comparable utilities**
12 **(peer group) determined?**

13 A. Along with the broad base of electric utilities, a peer group of comparable
14 electricity service providers is identified for purposes of gauging the utility
15 performance of KCPL. The peer group is determined using cluster analysis
16 techniques. Also, KCPL is compared to utilities that reside in the region that
17 surrounds its service territory.

18

19 The methodology used to determine the group of comparable service providers
20 is referred to as hierarchical clustering, where investor-owned utilities are
21 organized into a peer group according to five pre-defined cluster variables. The
22 variables used to cluster the utilities are the share of nuclear assets in total assets
23 where assets are measured as the real capital stock; the share of wholesale
24 energy sales in total sales (MWh); a measure of market density; the level of
25 energy sales (MWh); and the number of retail customers served. The final two

1 cluster variables are scale variables where the number of retail customers, when
2 coupled with MWh sales, tends to implicitly capture the load factor of the
3 utilities, at least to the degree that smaller customers have lower load factors
4 than larger customers. Because load factor is negatively correlated with average
5 cost, holding other factors constant, it is appropriate to group (cluster) the
6 utilities using these two output variables that capture the relative scale of
7 operation of the utilities. The cluster variables reflect the 2003 experience of
8 the utilities.

9

10 **Q. What are the data sources used in the study of KCPL performance?**

11 A. The Balanced Scorecard information is reported internally by the various
12 departments and organizations of KCPL. The other performance metrics
13 including retail prices, total factor productivity, and cost diagnostics rely upon
14 the revenue, sales quantities, costs, and input price data for the period
15 1994 – 2004. However, the development of the initial balance of the real capital
16 stock for 1994 involves data reaching back to 1965. The revenues, sales
17 quantities, capital assets, annual investment amounts, non-fuel operating
18 expenses, purchased power, labor compensation, fuel costs, peak demands,
19 depreciation rates, and property taxes of electricity service providers are
20 reported to the Federal Energy Regulatory Commission. The data are available
21 in the public domain, and the immediate study draws upon the reported data for
22 239 utilities. The study uses primary fuel price data including regional price
23 differences, as obtained from the Energy Information Administration. Capital
24 input prices are obtained from the survey of utility cost experience conducted
25 and published by Handy-Whitman, and are specific to the various types of

1 capital employed in providing integrated services. The price series for quasi-
2 material inputs is the U.S. GDP deflator.

3

4 **Q. For the defined metrics, please review the performance of Kansas City**
5 **Power and Light Company.**

6 A. For the defined metrics, Kansas City Power and Light has performed
7 exceptionally well. Pages 1 and 2 of Exhibit 2 show the level and trends in
8 annual residential prices and overall retail prices for the industry, the
9 comparison utility groups, and for KCPL. As can be observed, KCPL
10 residential prices were above the industry average at the beginning the period,
11 1994. KCPL largely through its substantial rate of productivity growth, has
12 steadily reduced the effective prices paid by retail consumers and, as a
13 consequence, KCPL is currently very competitive. As shown on page 2 of
14 Exhibit 2, overall retail prices show similar declines, where prices for retail
15 service provided by KCPL have declined at about 1.5% faster than that of the
16 industry, 1.75% faster than the peer group, and 0.70% faster than utilities in the
17 contiguous region.

18

19 Exhibit 3 shows the study results for Total Factor Productivity. As mentioned,
20 TFP is a comprehensive measure of productivity that accounts for all of the
21 inputs used to provide electricity services. Total Factor Productivity is the
22 single most important measure of performance, and Exhibit 3 compares the TFP
23 performance of KCPL with the TFP performance for the industry, the peer
24 group, and utilities of the surrounding region. As mentioned, TFP analysis
25 involves the determination of output levels, and inputs measured and estimated

1 for the types of inputs (fuel, capital, labor, quasi-materials) for each of the
2 service categories.

3
4 Page 1 of Exhibit 3 shows the TFP performance in generation, transmission, and
5 distribution operations. Since generation operations are the largest segment of
6 electric services, generation TFP will be a major determinant of overall TFP
7 performance for integrated services. Over 1994 – 2004, KCPL realized a rate of
8 TFP growth of 2.5%, which substantially exceeded the TFP growth achieved by
9 the industry (0.1%), peer group (-0.5%), or the contiguous area (0.5%). The
10 productivity of KCPL in generation services is near the top of the industry for
11 the 1994 – 2004 and 1998 – 2004 timeframes. For the earlier years 1994 –
12 1998, KCPL's performance is generally good, though it is largely limited by
13 exceptionally slow growth of energy sales. All sectors showed improved TFP
14 growth through 1998; following 1998, however, KCPL's TFP growth contrasts
15 sharply with the TFP decreases found in the other sectors.

16
17 Since transmission operations are a much smaller component of retail electric
18 services, these results are a smaller determinant of overall TFP performance.
19 KCPL transmission TFP declined 0.9% per year over the 1994 – 2004 period,
20 while the other groups experienced TFP increases. Differences between KCPL
21 and the other sectors were largest before 1998, as all comparison groups
22 including the peer group saw TFP declines after 1998. For distribution
23 operations, KCPL's TFP growth is nearly double the TFP growth for the
24 comparison groups. Specifically, KCPL TFP increased at an average annual
25 rate of 1.5%, while peer group TFP and contiguous area TFP increased 0.8%

1 per year, and industry wide TFP increased 0.7% per year. As is the case with
2 transmission TFP, all sectors showed larger TFP gains before 1998 than they
3 did after 1998.

4
5 Page 2 of Exhibit 3 presents the total factor productivity study results for
6 customer services and for integrated services as a whole. As mentioned,
7 customer service includes customer accounts, customer service and information,
8 and sales operations categories. Once again, KCPL TFP growth greatly
9 exceeded that achieved by the industry, the peer group, and the contiguous area.
10 Particularly noteworthy is the fact that KCPL TFP for customer service
11 operations increased at an average annual rate of 6.4% after 1998, more than
12 doubling the rates obtained by the industry. Also shown on page 2 is TFP
13 analysis for integrated services. Since KCPL outperformed the industry, peer
14 group, and contiguous region in most elements, we expect that KCPL's
15 company wide performance would demonstrate similar high levels. This is
16 indeed the case. As shown, KCPL's company wide TFP has increased at an
17 average annual rate of 2.6% for 1994 – 2004. This far surpasses the 1.0% per
18 year rate achieved by the contiguous area. The industry as a whole realized a
19 0.6% increase in TFP, while the peer group experienced no change over the
20 1994 – 2004 period.

21
22 Exhibit 4 shows the levels and trends for various cost diagnostics. Pages 1-4
23 provide measures of the relative concentration of capital per unit of output for
24 generation, transmission, and distribution services. The measure of output is
25 specific to each of the service categories, and reflects the most relevant attribute

1 of service for the category. For generation, the relevant measure of output is
2 energy (MWhs). Hence, the intensity of capital use in generation is normalized
3 (divided by) the quantity of MWhs produced. In the case of transmission and
4 distribution services, a relevant measure of output is peak demand, which is also
5 a main driver of power delivery services. Accordingly, the measure of capital
6 employed in transmission and distribution, for each of the utilities used in the
7 study including KCPL, is normalized by peak demands. Distribution capital is
8 also measured with respect to the level of customers served because, in addition
9 to peak demand, the number of customers is a major driver of investment in
10 distribution services.

11

12 Exhibit 4, page 1 (generation services) shows that KCPL uses capital more
13 intensively than the comparison groups, largely because of a high share of
14 nuclear power within its generation mix. The comparison groups and KCPL
15 reveal steady declines in the use of capital per unit of output during all periods,
16 which contributes to productivity, suggesting increases in resource use—i.e.,
17 greater output per unit of input. For the more recent timeframe, 1998 – 2004,
18 and the entire period (1994 – 2004) KCPL has obtained a greater use of capital
19 utilization than the industry, peer group, or the contiguous region. While
20 KCPL’s level of capital use in generation is comparatively high because of the
21 presence of nuclear power, KCPL’s gains in resource utilization sharply
22 narrowed the difference with respect to the other utilities by 2004. KCPL
23 reduced the amount of generation capital per megawatt-hour at a rate of 3.40%
24 per year over the entire period.

1 Page 2 of Exhibit 4 presents the intensity of capital use in transmission, while
2 page 3 presents the capital intensity measure for distribution. Whereas KCPL
3 uses less transmission capital per unit of peak demand than the comparison
4 groups, KCPL uses comparatively more distribution capital. The sharp
5 difference in the relative levels of transmission and distribution capital stated on
6 a per-unit-of-output (MW) basis suggests differences in the classification of
7 power delivery facilities as transmission and distribution. As mentioned earlier,
8 it is more important to focus on the general trends, where KCPL has
9 experienced substantial gains at rates that are roughly equivalent to or better
10 than the industry, the peer group, and the utilities of the contiguous region.

11

12 Page 4 of Exhibit 4 shows O&M performance for distribution services on a per
13 customer basis. Page 5 of Exhibit 4 presents relative fuel costs and, as can be
14 seen, KCPL has a large advantage in level over all periods and in trends over
15 1998 – 2004 and 1994 – 2004. The final set of cost diagnostics, as shown on
16 pages 6 through 9 of Exhibit 4, present the intensity of operations and
17 maintenance (O&M) expenses per unit of capital. For generation services,
18 KCPL's non-fuel O&M levels are at the lower side of the levels for the
19 comparison groups through the year 2000, and are below the comparison group
20 from 2000 forward. The trends in non-fuel O&M expenses per unit of capital
21 reveal that KCPL's experience is fairly high over the 1994 – 1998 timeframe, to
22 be followed by sharply improved performance for 1998 – 2004, which is also
23 the case for the utilities of the surrounding region. Over the entire period, the
24 contiguous region out-performed the KCPL by 0.60%. Pages 7 and 8 of Exhibit
25 4 present the results for transmission and distribution. KCPL's O&M expenses

1 in transmission are fairly low until 2004 and, as with O&M expenses for other
2 utilities of the region, show substantial increases over the entire period. For
3 distribution, KCPL's O&M expenses are equivalent to that of the industry, the
4 peer group, and the contiguous region, on a unit of capital basis, and are rising
5 more rapidly than other utilities on average. While it is useful to examine
6 individual cost diagnostics of power delivery, the most relevant measure of
7 overall performance is the total bundle of resources employed including both
8 capital and O&M expenses and, on the basis, KCPL demonstrates substantial
9 gains in resource utilization, and productivity as well.

10

11 In terms of the customer service area, the operations and maintenance costs per
12 customer served, for KCPL at the beginning of the study period, were at a level
13 equivalent to the industry and the comparison groups. This advantage was
14 eliminated in the late 1990's. Since then, however, the very large gains in cost
15 performance have sharply reduced KCPL's customer service operations and
16 maintenance costs by the end of the study period. Over the entire study period,
17 KCPL reduced customer service operations and maintenance costs substantially,
18 and has sharply out-performed the industry and the comparison groups. For the
19 industry, customer service operations and maintenance costs per customer
20 increased over the study period, although only slightly.

21

22 Exhibit 5 shows results for four key indicators of KCPL's Corporate Scorecard
23 process. As can be seen, KCPL has satisfied its target levels for *Customer*
24 *Satisfaction*, and we observe increases in performance according to the metric
25 *% Customers Returned to Service in 2 Hours*, where performance has increased

1 from 72% for 2004 to 79% for 2005. Similarly, *Customer Service and Call*
2 *Speed of Response* also shows slightly improved performance between 2004
3 (75%) and 2005 (77%). On the other hand, the *System Average Interruption*
4 *Duration Index* metric shows that, as expected at November 2005, the Company
5 would fall short of the target level of 60.8 for 2005, with an estimated score of
6 56.4. The SAIDI index of reliability is sensitivity to random weather events,
7 and reliability performance should only be gauged over several years.

8
9 **Q. Please summarize the results of the performance study of Kansas City**
10 **Power and Light Company.**

11 A. Our analyses reveal that, for the defined metrics most relevant to retail markets,
12 with particular emphasis on the trends over time, Kansas City Power and Light
13 has performed near the top of the electric services industry for the 1994 – 2004
14 timeframe. As I discussed earlier, the most important and revealing measure of
15 overall long-term performance is total factor productivity, which is literally
16 process efficiency; indeed, growth in productivity along with innovation is the
17 key driver of the success of firms, industries, and economies. For these years,
18 Kansas City Power and Light has achieved one of the highest levels of
19 productivity improvement in the U.S. electric industry.

20
21 From the outset, the purpose of the study was to perform an independent and
22 objective assessment of KCPL's performance. Accordingly, the study approach
23 takes a fairly comprehensive view in its assessment of performance, including
24 the relative costs, productivity, and service prices of KCPL with respect to
25 comparable electricity service providers. To ensure comparability, the

1 assessment relies to a substantial extent on data and information that is available
2 within the public domain. The study results including the quantitative
3 assessment as well as other evidence affirm that, without question, Kansas City
4 Power and Light Company has obtained a very high level of performance from
5 the perspective of retail consumers over recent years.

6

7 **Q. Please review recent changes in the electric utility industry and how are**
8 **such changes impacting capital risks, the cost of equity, and the need for an**
9 **adequate rate of return.**

10 A. It is perhaps useful to begin with a review of events, changes, and the renewed
11 challenges that confront the electricity services industry. Generally, structural
12 change refers to changes in government policy, technology, and market rules.
13 Most relevant to the electric industry today are the changes that reach back to
14 the Public Utility Regulatory Policies Act (PURPA) of 1978. PURPA
15 incorporated a number of provisions. In particular, PURPA established so-
16 called Qualifying Facilities (QFs) status, and assigned the authority for
17 determination of QF status to the Federal Energy Regulatory Commission
18 (FERC). QF status is set aside for certain renewable resources, and is mostly
19 targeted at cogeneration facilities. Once awarded QF status such facilities are
20 entitled to sell power to the incumbent service provider at avoided costs, as
21 determined by state regulatory authorities. QF generators evolved and
22 expanded to include wholesale power merchants referred to as Non-Utility
23 Generators (NUGs) that, within a few years, became a sizable sector of
24 wholesale markets. In brief, QFs allowed for market entry into wholesale
25 generation services, and ushered in an era of competition.

1 The introduction of NUGs such as AES Corporation and Sythe Industries
2 appeared to be successful and, given the comparatively high cost of embedded
3 generation of the incumbent service provider at the time, the notion of
4 competitive generation services held substantial appeal during the late 1980s.
5 The apparent success of competitive entry coupled with the growing interest in
6 regulatory reform gave rise to Title VII of the Energy Policy Act of 1992, which
7 created Exempt Wholesale Generators (EWGs) and required incumbent
8 transmission service providers, mostly integrated electric utilities, to open their
9 networks to third parties that wished to wheel power among wholesale power
10 suppliers and purchasers.

11

12 Though initially small, wholesale transaction volume expanded rapidly
13 beginning about 1996. Flourishing wholesale markets by 1997 precipitated a
14 number of private generation companies, many of which were subsidiaries of
15 integrated electric companies, and power trading operations run by commodity
16 trading firms such as Williams Energy, Morgan Stanley, and Enron to name a
17 few. Even public authorities such as TVA established wholesale trading floors.
18 The sheer volume of transactions coupled with the expanding growth of retail
19 loads due to the robust economy of the late 1990s challenged system reliability
20 within both the Eastern and Western Interconnections during this timeframe.
21 Importantly, the narrowing of supply margins and the appearance of congested
22 networks, as evidenced by a sharp rise in Transmission Load Relief (TLR)
23 actions of transmission providers, caused a huge increase in the volatility in
24 regional wholesale market prices, thus exposing buyers and sellers (including

1 utilities, and investors in utilities and energy companies involved in wholesale
2 power markets) to sharply higher risks.

3

4 Market participants including some regulators, perceived the need for the
5 reform of wholesale market arrangements to obtain price discovery, to ensure
6 efficient management of congestion, and to achieve efficient transaction
7 scheduling. In response, the Federal Energy Regulatory Commission expended
8 a decade in implementing waves of market reform, as evidenced in key
9 initiatives including the Open Access Transmission Tariff of Order 888, OASIS
10 Sites of Order 889, the Capacity Reservation Tariff (CRT), Order 2000 giving
11 rise to Regional Transmission Organizations (RTOs), and Standard Market
12 Design (SMD) of 2002 which now appears to be effectively closed.

13

14 The experience of the industry regarding market restructuring which assets sales
15 by incumbent utilities, a much larger presence of independent generation, and
16 highly volatile wholesale markets, has not gone unnoticed by shareholders. The
17 essential point is that perceived risks are higher for the industry currently than in
18 the past. A few highlights are noteworthy:

19 1) The restructuring of the wholesale electricity market may
20 potentially provide gains to retail consumers. Getting there is proving
21 to be challenging. Key attributes of power systems including non-
22 storability and network externalities imply that wholesale power
23 prices can demonstrate unusually high levels of price volatility.
24 Volatility of market prices increases risks, real and perceived, of
25 investment in the industry.

1 2) Transmission issues abound. Concerns include potential
2 overlap in jurisdiction regarding transmission, the implications for
3 recovery of investment cost in transmission, and the impact of
4 transmission on earnings of service providers. As an example,
5 under mandates contained in the Energy Policy Act of 2005, the
6 FERC will apparently assume an enlarged role in electric
7 reliability and the expansion of transmission networks at the
8 regional level. Transmission limits can continue to impede
9 delivery over the foreseeable future.

10 3) Uncertainty about the future path of the industry. At one point,
11 it appeared that a structure involving locational pricing, unbundled
12 generation services, and an overlay of financial transmission
13 rights was the only feasible path for wholesale market design.
14 However, that view may not represent a consensus, and there is
15 considerable uncertainty regarding the path and end state of
16 wholesale market restructuring. Locational markets have been
17 adopted in some regions of U.S. markets. However, there appears
18 to be considerable interest in alternative approaches in the
19 organization of wholesale markets at this time.

20

21 I wish to emphasize that investors understand risks, and appreciate the various
22 dimensions of risk of the electricity industry, particularly where considerable
23 new construction is on the horizon. While the outcomes regarding some of
24 these issues are uncertain, the implications are clear. Specifically, private
25 investors, commercial banks, mutual funds, investment bankers, and financial

1 rating agencies are increasingly concerned about financial stability in view of
2 the risks discussed above. Arguably, the electricity services industry as whole
3 carries larger business, regulatory, and financial risks currently than in previous
4 eras.

5

6 **Q. Do these considerations regarding investment in the electric industry**
7 **warrant the concern of the Missouri Public Service Commission and the**
8 **setting of electricity prices?**

9 A. Yes, absolutely. As we discuss in detail above, the financial risks harbored by
10 investors relate to the more uncertain business and regulatory environment
11 confronting electricity service providers currently. These higher risks are
12 present at a time when KCPL must raise substantial amounts of external capital
13 in order to fund its investment needs.

14

15 **Q. Are there other considerations that the Missouri Public Service**
16 **Commission should use to determine the return on equity?**

17 A. Yes. I encourage the Commission to make special recognition of the high
18 standard of productivity and overall performance achieved by KCPL over recent
19 years, in its deliberation of the return on equity and revenue requirement in the
20 immediate docket. The Company has adopted and implemented business
21 practices and procedures that have enabled the Company to sustain a clear cost
22 advantage through high growth of productivity improvement. In the long term,
23 the actions of the Company translate directly into benefits to retail customers
24 through lower customer bills, which have been and are realized without
25 compromise to delivered reliability and service.

1 **Q. Are there circumstances where the Commission should depart from**
2 **estimates of the cost of equity capital in setting the rate of return, and are**
3 **such circumstances currently present?**

4 A. Yes. In determining the rate of return level, the Commission should take a broad
5 view that fully accounts for the long-term interests of retail consumers and the
6 region, while also providing an adequate and fair return to investors. The
7 interests of the community are particularly important in KCPL's immediate
8 filing in view of the resource plan.

9
10 What sets this situation apart, however, is the strong, positive link and
11 interdependency between the interests of the region, and adequate returns to
12 shareholders.

13
14 More specifically, the schedule for implementation of KCPL's resource plan, as
15 reached through its consultative process with stakeholders, is vital to retail
16 markets and consumers served by the Company, and to the larger region. As
17 discussed elsewhere in our filing, the resource plan requires substantial
18 investment. To raise the needed external capital at reasonable terms, the
19 Company must satisfy defined credit requirements during current periods for
20 financial reporting. During these periods, however, the Company and investors
21 face considerable uncertainty and risks in the form of outside events—gas
22 markets, weather, and unit availability to name a few. Consequently, it is
23 absolutely necessary that the Commission set the authorized return at a
24 sufficient level, so that the construction program can proceed with delay, in the

1 presence of certain events. In short, adequate rate of return accommodates
2 risks, thus enabling the implementation of the new resources in timely fashion.

3

4 **Q. If the Commission is to depart from the estimated cost of capital in setting**
5 **the authorized rate of return, how is that to be implemented? What**
6 **mechanism is available to the Commission?**

7 A. A potential mechanism is to incorporate a performance allowance into the rate
8 of return. A performance allowance is of substantial value to retail consumers
9 in the current timeframe, where the Company is in the midst of implementing
10 the resource plan. The benefits arising from an allowance in the rate of return
11 assume three dimensions:

12 1. Accommodation of Risk. The allowance contributes to the resource
13 plan by providing assurance that the returns to capital are sufficient to
14 enable the Company to raise new capital on reasonable terms, in view
15 of heightened uncertainty associated with construction and other
16 factors, such as those discussed above.

17 2. Endorsement. An allowance by the regulatory agency overseeing
18 electricity markets in Missouri conveys to capital markets that the
19 regulators are behind the resource plan, as assembled and agreed to by
20 stakeholders and KCPL.

21 3. Alignment of Long-term Performance with the Interests of Consumers.
22 An allowance identifies the importance of market performance by
23 utilities, as a basis for realized returns to capital.

1 **Q. If the Missouri Public Service Commission is to consider a performance**
2 **allowance for the rate of return on common equity, what criteria and**
3 **guideline should the Commission use to determine the level for the**
4 **allowance?**

5 A. We recommend that the Commission apply a rational principle and criterion in
6 the determining the appropriate level of a performance allowance inclusion
7 within the rate of return. In brief, the Commission should ensure that the net
8 benefits to electricity consumers, as obtained by the allowance, are sufficient to
9 cover the allowance itself. By satisfying this criterion, consumers and the State
10 of Missouri are better off, and thus well served. Second, the allowance should
11 be of sufficient magnitude that it provides real benefits as mentioned above, and
12 is not lost in the noise of routine business operations. In essence, the
13 Commission should establish an allowance that is adequate to the task at hand,
14 of 50 – 100 basis points.

15
16 **Q. Can you please summarize your analysis, findings, and recommendations**
17 **as regarding the performance assessment of Kansas City Power and Light**
18 **and the implications for the return on equity recommendations?**

19 A. Yes. Kansas City Power and Light, as our study amply demonstrates, has
20 obtained a very high standard of market performance from the perspective of
21 retail consumers. Our performance study utilizes four categories of metrics.
22 The most important of these is total factor productivity, which captures the on-
23 going improvement in resource efficiency and utilization. By this measure,
24 KCPL has achieved a high standard of overall performance during the
25 1994 – 2004 timeframe. The Commission should recognize the performance of

1 KCPL and take account of the special circumstances attending the resource plan
2 and the need for external capital for its implication. To this end, I recommend
3 that the Missouri Public Service Commission consider the incorporation of a
4 performance allowance into the allowed rate of return on equity for the
5 applicant Kansas City Power and Light, in the determination of the revenue
6 requirement in the current docket.

Exhibit 1
Names of Utilities Incorporated In the Performance Study
(Industry Wide, Peer Group, and Contiguous Region)

Industry Wide

Alabama Power Company
Allete, Inc.
Appalachian Power Company
Aquila, Inc.
Arizona Public Service Company
Avista Corporation
Black Hills Power, Inc.
Carolina Power & Light Company
Central Vermont Public Service Corporation
Cleco Power LLC
Columbus Southern Power Company*
Dayton Power and Light Company*
Duke Energy Corporation
El Paso Electric Company
Empire District Electric Company
Entergy Arkansas, Inc.*
Entergy Gulf States, Inc.
Entergy Louisiana, Inc.
Entergy Mississippi, Inc.*
Entergy New Orleans, Inc.
Florida Power & Light Company
Florida Power Corporation
Georgia Power Company
Green Mountain Power Corporation
Gulf Power Company
Hawaiian Electric Company, Inc.
Idaho Power Company*
Indianapolis Power & Light Company*
Kansas Gas and Electric Company
Kentucky Utilities Company*
Louisville Gas and Electric Company
MDU Resources Group, Inc.
Mississippi Power Company
Monongahela Power Company*
Nevada Power Company*
Northern Indiana Public Service Company*
Northern States Power Company
(Minnesota)
Ohio Power Company
Oklahoma Gas and Electric Company*
Otter Tail Corporation
Portland General Electric Company*
PSI Energy, Inc.
Public Service Company of Colorado
Public Service Company of New Mexico

Public Service Company of Oklahoma*
Sierra Pacific Power Company
South Carolina Electric & Gas Company*
Southern Indiana Gas and Electric Company
Southwestern Electric Power Company*
Southwestern Public Service Company*
Tampa Electric Company*
Tucson Electric Power Company
Union Electric Company
Virginia Electric and Power Company
Westar Energy, Inc.

Peer Group

Columbus Southern Power Company
Dayton Power and Light Company
Entergy Arkansas, Inc.
Entergy Mississippi, Inc.
Idaho Power Company
Indianapolis Power & Light Company
Kentucky Utilities Company
Monongahela Power Company
Nevada Power Company
Northern Indiana Public Service Company
Oklahoma Gas and Electric Company
Portland General Electric Company
Public Service Company of Oklahoma
South Carolina Electric & Gas Company
Southwestern Electric Power Company
Southwestern Public Service Company
Tampa Electric Company

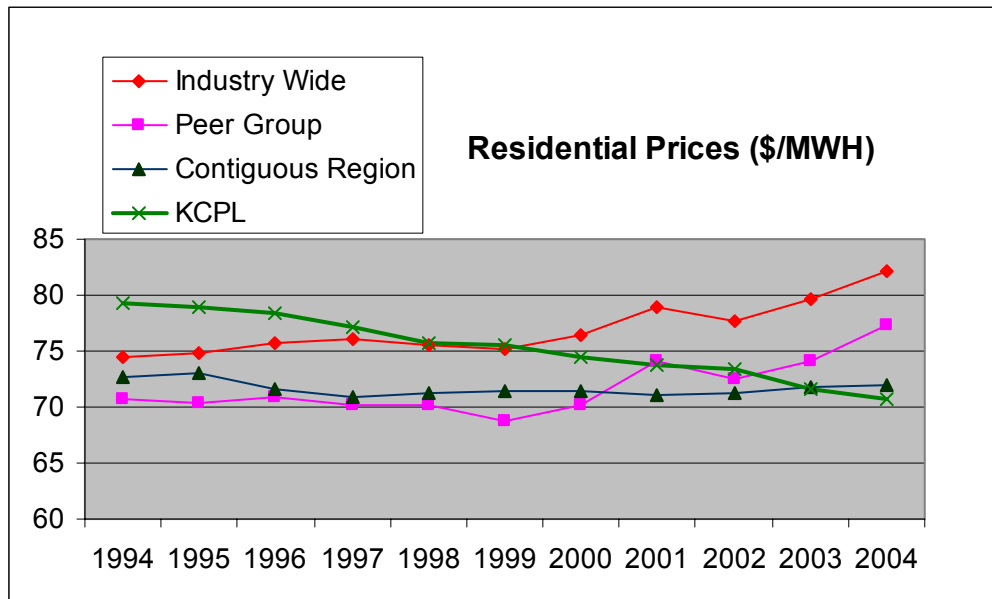
Contiguous Region

Aquila, Inc.
Empire District Electric Company
Kansas Gas and Electric Company
Oklahoma Gas and Electric Company
Union Electric Company
Westar Energy, Inc.

*Also a member of the Peer Group.

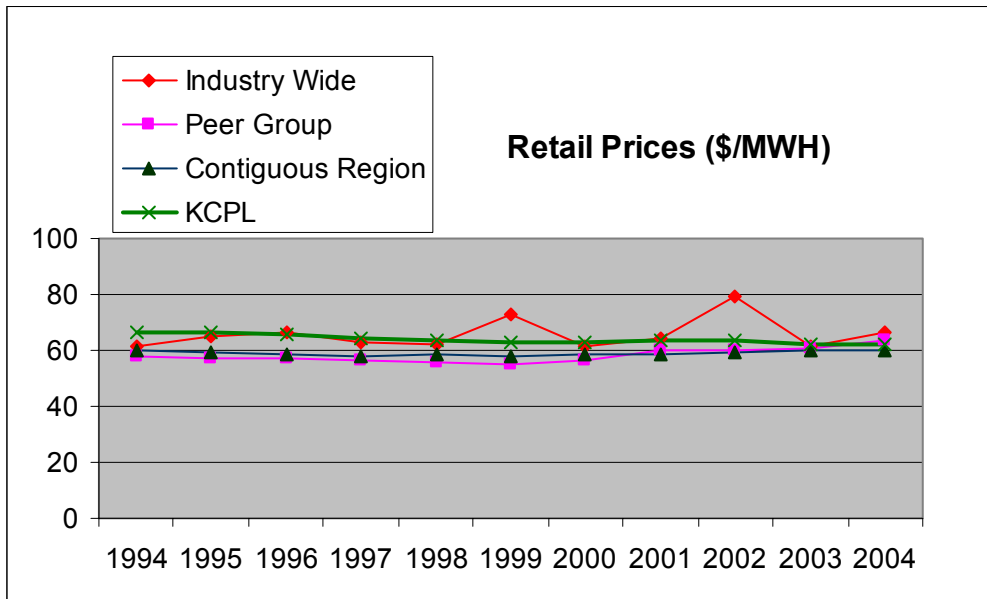
Exhibit 2 Retail Price Performance

	Annual Rate of Change		
	1994-1998	1998-2004	1994-2004
Industry Wide	0.36%	1.40%	0.98%
Peer Group	-0.18%	1.61%	0.90%
Contiguous Region	-0.47%	0.15%	-0.09%
KCPL	-1.14%	-1.12%	-1.13%



**Exhibit 2 (continued)
Retail Price Performance**

	Annual Rate of Change		
	1994-1998	1998-2004	1994-2004
Industry Wide	0.47%	1.14%	0.87%
Peer Group	-0.73%	2.15%	1.00%
Contiguous Region	-0.61%	0.37%	-0.02%
KCPL	-1.34%	-0.35%	-0.74%



**Exhibit 3
Productivity**

Generation TFP Growth Rates									
	1994-1998			1998-2004			1994-2004		
	TFP	Output	Input	TFP	Output	Input	TFP	Output	Input
Industry Wide	3.0%	3.9%	0.9%	-1.8%	-0.2%	1.5%	0.1%	1.4%	1.3%
Peer Group	2.5%	3.7%	1.2%	-2.6%	-1.6%	1.0%	-0.5%	0.5%	1.1%
Contiguous Area	1.3%	2.6%	1.3%	-0.1%	1.3%	1.4%	0.5%	1.8%	1.4%
KCPL	1.6%	0.6%	-1.1%	3.1%	3.7%	0.5%	2.5%	2.4%	-0.1%

Transmission TFP Growth Rates									
	1994-1998			1998-2004			1994-2004		
	TFP	Output	Input	TFP	Output	Input	TFP	Output	Input
Industry Wide	2.0%	1.9%	0.0%	-0.6%	0.6%	1.1%	0.4%	1.1%	0.7%
Peer Group	2.5%	2.2%	-0.3%	-1.5%	0.4%	2.0%	0.1%	1.2%	1.1%
Contiguous Area	6.2%	6.0%	-0.2%	-2.0%	0.3%	2.3%	1.3%	2.6%	1.3%
KCPL	0.3%	2.0%	1.7%	-1.7%	0.8%	2.5%	-0.9%	1.3%	2.2%

Distribution TFP Growth Rates									
	1994-1998			1998-2004			1994-2004		
	TFP	Output	Input	TFP	Output	Input	TFP	Output	Input
Industry Wide	1.6%	2.5%	0.9%	0.1%	1.4%	1.3%	0.7%	1.8%	1.1%
Peer Group	2.0%	2.9%	0.9%	0.0%	1.4%	1.4%	0.8%	2.0%	1.2%
Contiguous Area	2.7%	3.4%	0.7%	-0.4%	0.8%	1.2%	0.8%	1.9%	1.0%
KCPL	3.3%	2.6%	-0.6%	0.3%	1.3%	1.0%	1.5%	1.8%	0.3%

**Exhibit 3 (continued)
Productivity**

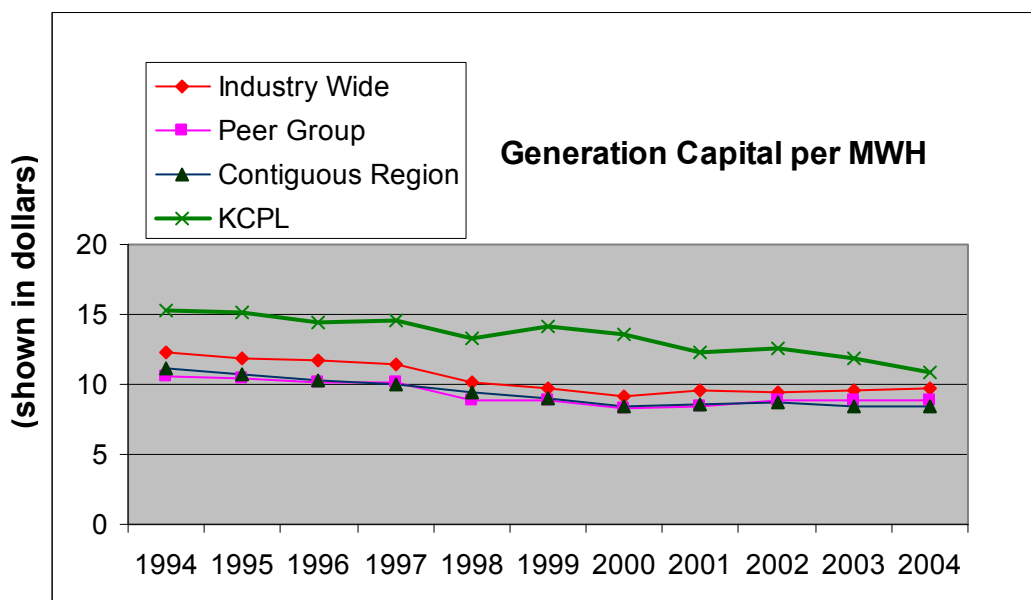
Customer Service TFP Growth Rates									
	1994-1998			1998-2004			1994-2004		
	TFP	Output	Input	TFP	Output	Input	TFP	Output	Input
Industry Wide	2.8%	1.7%	-1.1%	3.2%	1.5%	-1.7%	3.0%	1.6%	-1.5%
Peer Group	4.0%	1.8%	-2.1%	3.0%	1.6%	-1.3%	3.4%	1.7%	-1.6%
Contiguous Area	5.5%	1.4%	-4.1%	2.4%	1.0%	-1.4%	3.6%	1.1%	-2.5%
KCPL	2.1%	1.4%	-0.8%	6.6%	1.6%	-5.0%	4.8%	1.5%	-3.3%

Total Company TFP Growth Rates									
	1994-1998			1998-2004			1994-2004		
	TFP	Output	Input	TFP	Output	Input	TFP	Output	Input
Industry Wide	2.8%	4.5%	1.7%	-0.8%	1.0%	1.8%	0.6%	2.4%	1.8%
Peer Group	2.4%	4.4%	2.1%	-1.6%	0.0%	1.6%	0.0%	1.8%	1.8%
Contiguous Area	2.4%	3.5%	1.2%	0.2%	1.0%	0.9%	1.0%	2.0%	1.0%
KCPL	3.7%	3.1%	-0.7%	1.9%	2.3%	0.4%	2.6%	2.6%	0.0%

Exhibit 4 Cost Diagnostics

Annual Rate of Change

	1994-1998	1998-2004	1994-2004
Industry Wide	-5.05%	-0.68%	-2.43%
Peer Group	-4.15%	-0.18%	-1.77%
Contiguous Region	-4.31%	-1.82%	-2.82%
KCPL	-3.58%	-3.29%	-3.40%



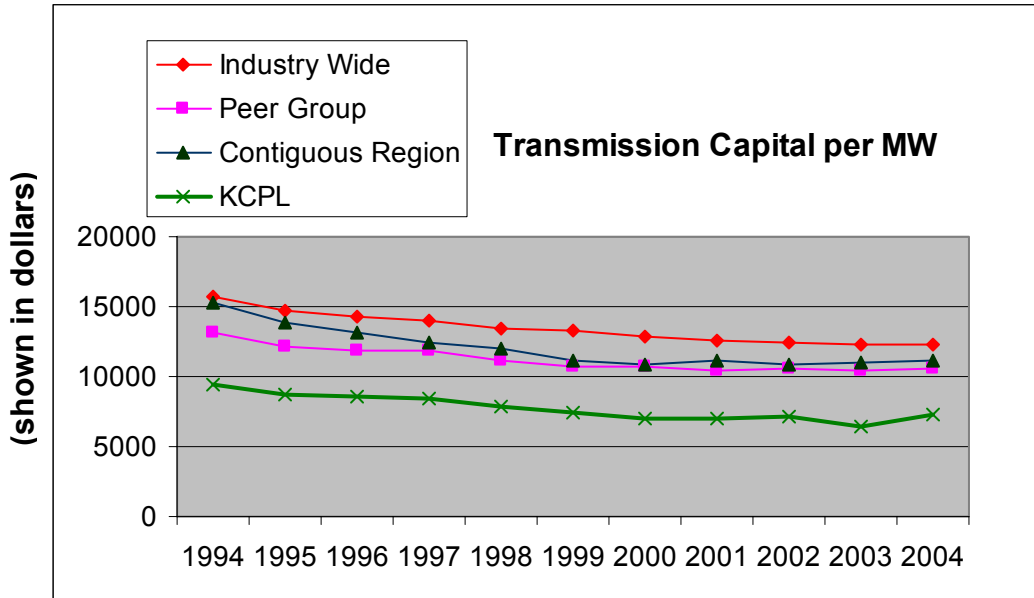
NOTE: The values shown above are the per unit of output-based rental value of capital resources, where the rental values reflect capital valued in 1984 dollars. As discussed in the technical appendix, rental value of capital is developed by employing the Christensen-Jorgensen methodology, which has been widely applied in productivity analysis in the United States and worldwide.

As an example, presume a load factor of 0.60, so that 1 MW of peak load translates into 5256 MWh of energy, annually. A rental value of capital of, say, \$12,000, is equal to \$2.28 per MWh, or 2.3 mills per kWh. With a capital charge rate including returns to capital, income taxes, and property taxes of approximately 14%, the implied value of the stock, which is equal to the per unit price of the stock times the quantity, is equal to \$16 per MWh or about \$85 per kW of demand.

Exhibit 4 (continued)
Cost Diagnostics

Annual Rate of Change

	1994-1998	1998-2004	1994-2004
Industry Wide	-3.79%	-1.46%	-2.39%
Peer Group	-4.09%	-0.82%	-2.13%
Contiguous Region	-5.96%	-1.40%	-3.23%
KCPL	-4.45%	-1.22%	-2.51%



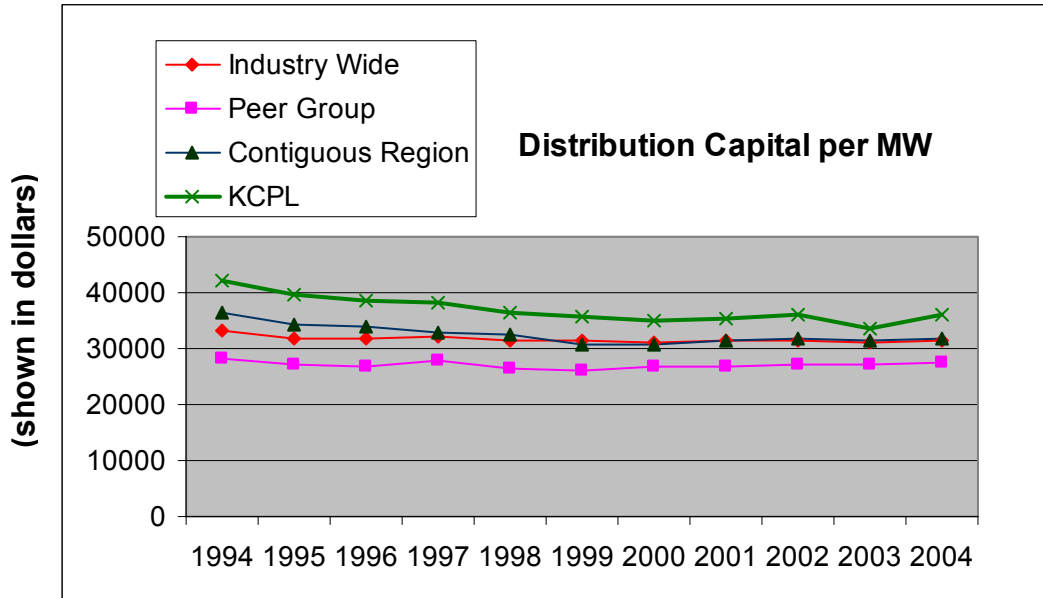
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Exhibit 4 (continued)
Cost Diagnostics

Annual Rate of Change

	1994-1998	1998-2004	1994-2004
Industry Wide	-1.29%	-0.04%	-0.54%
Peer Group	-1.53%	0.45%	-0.34%
Contiguous Region	-3.07%	-0.34%	-1.44%
KCPL	-3.70%	-0.23%	-1.61%



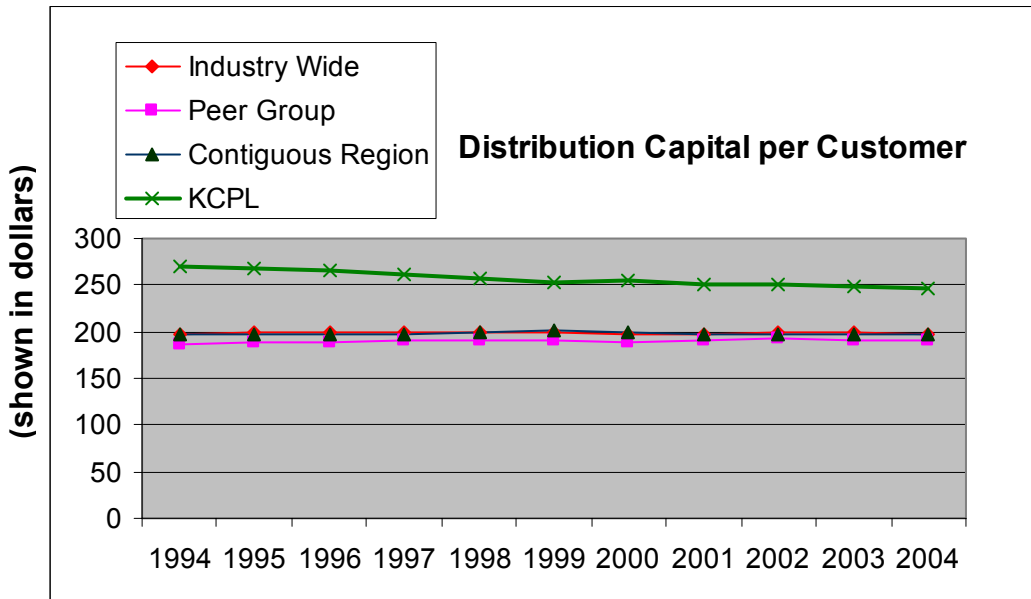
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Exhibit 4 (continued)
Cost Diagnostics

Annual Rate of Change

	1994-1998	1998-2004	1994-2004
Industry Wide	0.16%	-0.12%	-0.01%
Peer Group	0.60%	-0.06%	0.20%
Contiguous Region	0.32%	-0.12%	0.06%
KCPL	-1.13%	-0.75%	-0.90%



NOTE: The values shown above are the per unit of output-based rental value of capital resources, where the rental values reflect capital valued in 1984 dollars. As discussed in the technical appendix, rental value of capital is developed by employing the Christensen-Jorgensen methodology, which has been widely applied in productivity analysis in the United States and worldwide.

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Exhibit 4 (continued)
Cost Diagnostics

Annual Rate of Change

	1994-1998	1998-2004	1994-2004
Industry Wide	-0.77%	6.82%	3.79%
Peer Group	-1.41%	5.93%	2.99%
Contiguous Region	0.62%	2.77%	1.91%
KCPL	0.73%	0.19%	0.40%

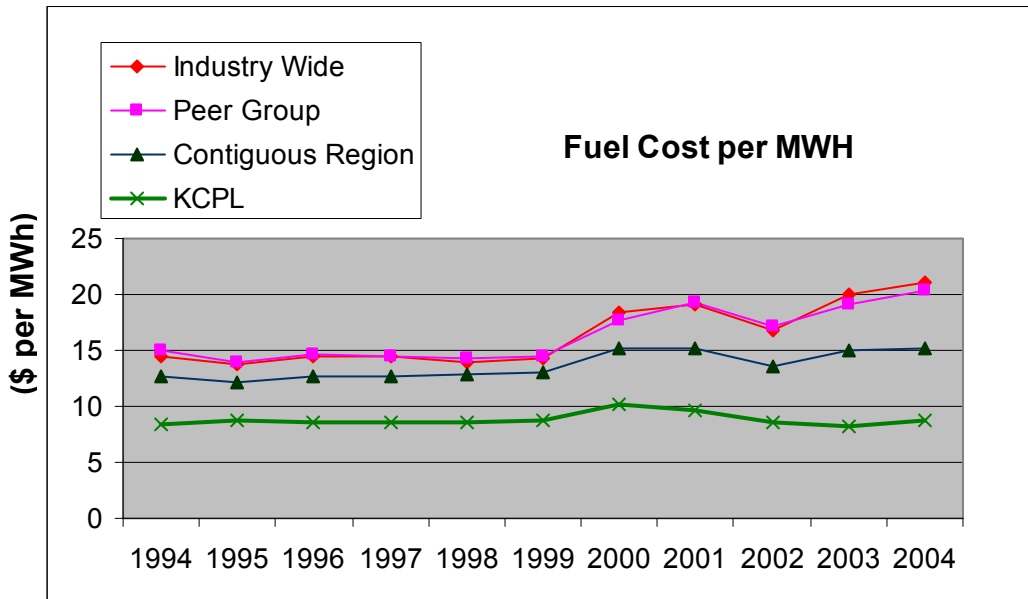


Exhibit 4 (continued)
Cost Diagnostics

Annual Rate of Change

	1994-1998	1998-2004	1994-2004
Industry Wide	-0.03%	6.80%	4.07%
Peer Group	-1.04%	11.12%	6.26%
Contiguous Region	5.40%	1.27%	2.92%
KCPL	4.57%	2.78%	3.50%

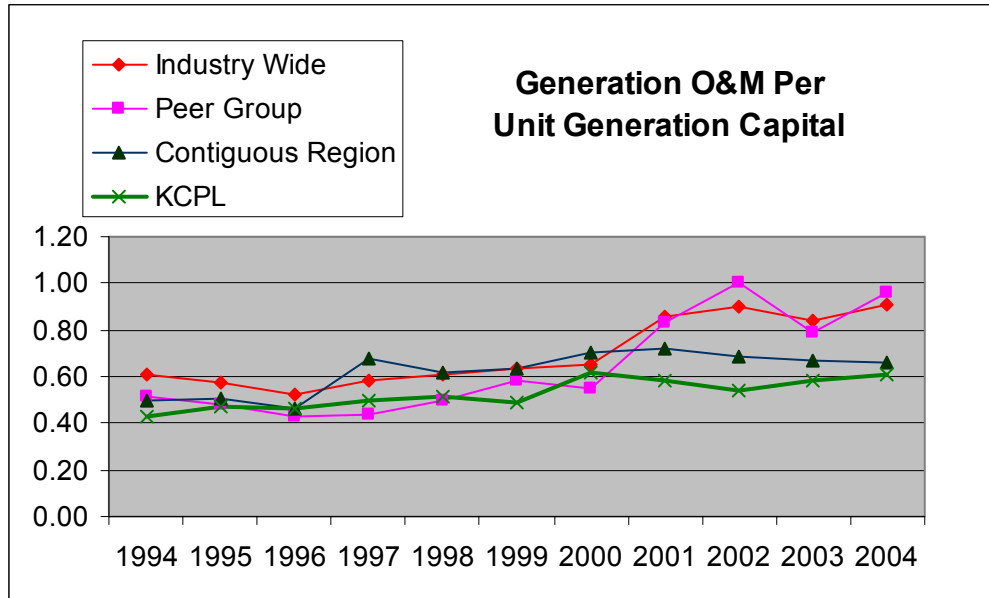


Exhibit 4 (continued)
Cost Diagnostics

Annual Rate of Change

	1994-1998	1998-2004	1994-2004
Industry Wide	4.48%	8.20%	6.71%
Peer Group	1.67%	9.88%	6.60%
Contiguous Region	9.28%	17.46%	14.18%
KCPL	10.16%	13.14%	11.95%

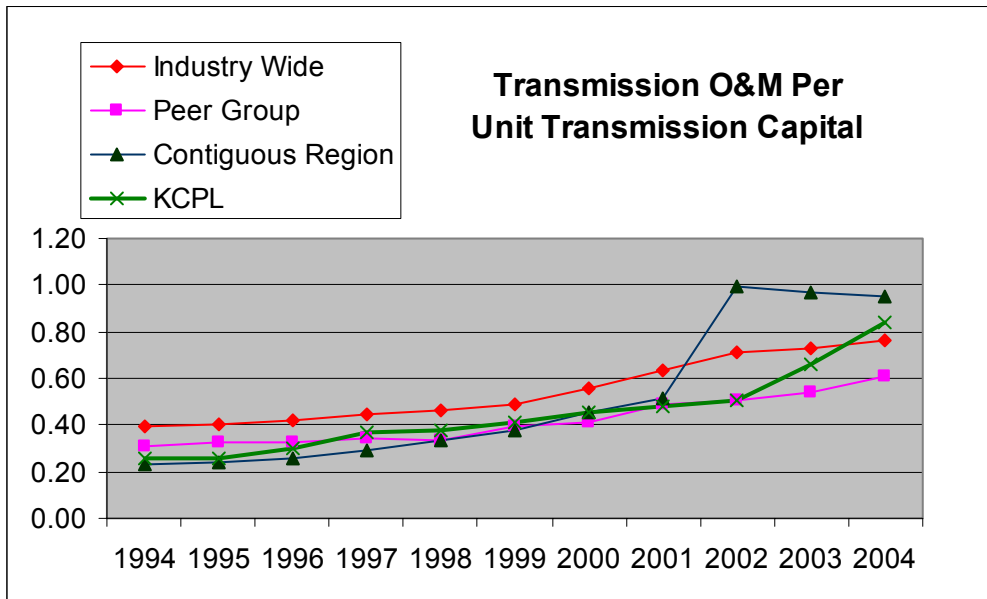


Exhibit 4 (continued)
Cost Diagnostics

Annual Rate of Change

	1994-1998	1998-2004	1994-2004
Industry Wide	-0.02%	2.44%	1.46%
Peer Group	-2.90%	1.92%	-0.01%
Contiguous Region	2.06%	1.51%	1.73%
KCPL	-1.03%	3.87%	1.91%

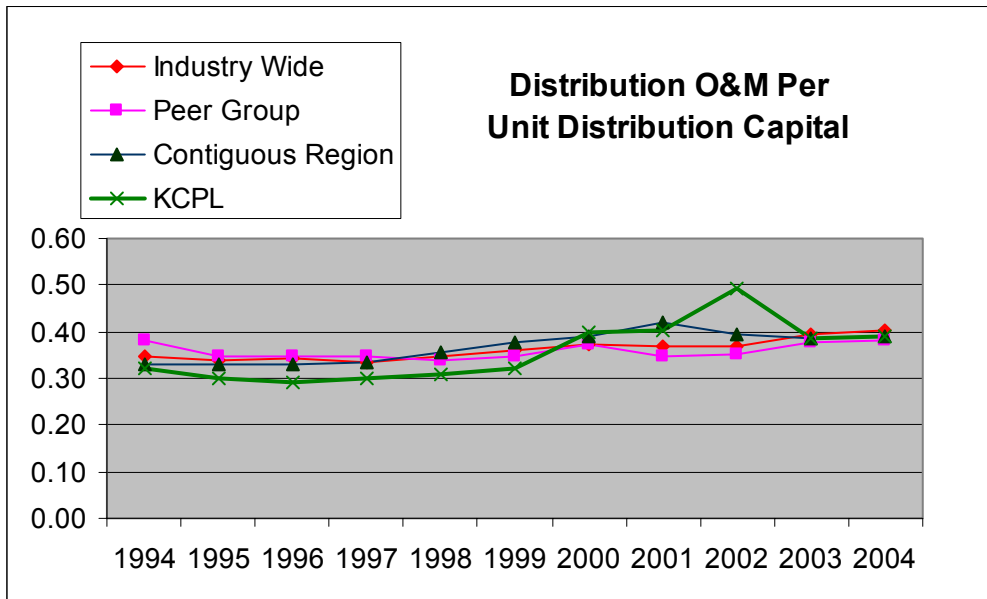


Exhibit 4 (continued)
Cost Diagnostics

Annual Rate of Change

	1994-1998	1998-2004	1994-2004
Industry Wide	2.59%	-1.21%	0.31%
Peer Group	-1.30%	-0.04%	-0.54%
Contiguous Region	-0.85%	-1.84%	-1.45%
KCPL	2.33%	-5.83%	-2.57%

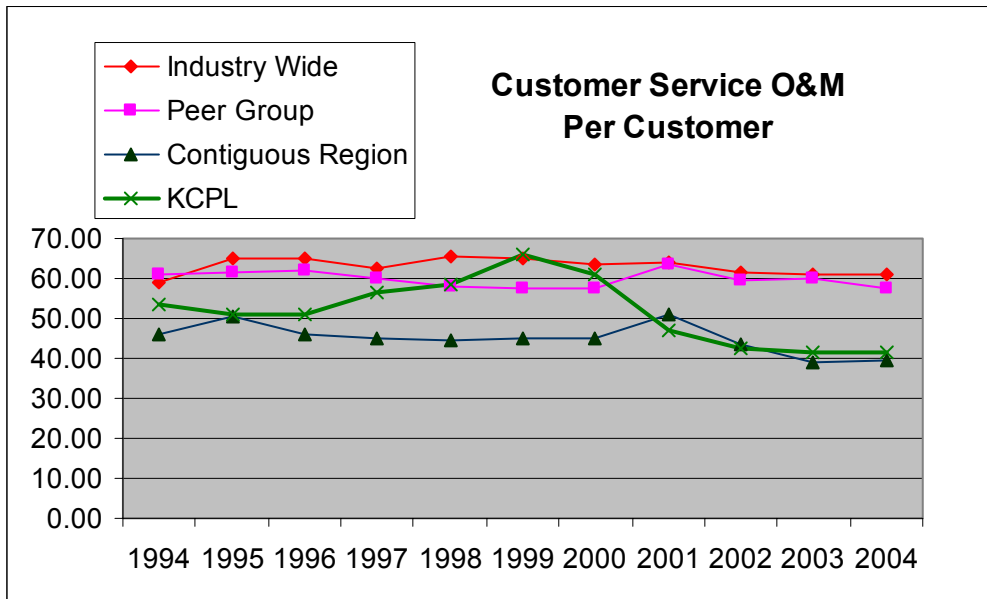


Exhibit 5
Selected Metrics of Kansas City Power and Light's Balanced Scorecard

	<u>2004</u>	<u>2005</u>
Customer Satisfaction Index	97	97 – 101
SAIDI Index of Reliability	68.9	56.4
% Customers Returned to Service In 2 Hours	72%	79%
Customer Service and Call Speed of Response (% within 30 sec)	75%	77%

TECHNICAL DISCUSSION PAPER

**TOTAL FACTOR PRODUCTIVITY
of the
U.S. ELECTRIC UTILITY INDUSTRY**

**Christensen Associates Energy Consulting LLC
Madison, Wisconsin
January, 2006**

This discussion reviews the methods used to construct total factor productivity (TFP) performance measures for Kansas City Power and Light and other investor-owned electric utilities. A comprehensive TFP measure, which evaluates all utility operations together, is developed for generation, transmission, distribution, and customer service categories of integrated services.¹ The estimation of TFP performance metrics requires the development of measures of output and inputs used in the process of providing electric services. Inputs include labor, quasi-materials, capital, and fuel.

Output Measures

The following measures were used to measure output. First, the comprehensive (company wide) measure of TFP for integrated services uses total MWH sales covering the various retail customer classes and sales in wholesale markets. The output measure used is a Fisher ideal quantity index of MWH sales to residential customers, commercial customers, industrial customers, and MWH sales for resale. The weights used for these measures are based on revenues realized from the sales to each customer class.²

For generation operations, the output measure used is net generation. For transmission operations, the study uses annual peak MW and total miles of transmission lines as the measure of output. We average the annual growth rates for these two output measures, and then compute an output index by obtaining an annual average growth rate. For distribution operations, the output measure is peak MW and the number of customers, using the same averaging procedure as employed to compute transmission output. The output measure for customer service is the number of customers.

¹ Customer service includes the functional accounting categories of customer accounts, customer service and informational, and sales.

² A Fisher ideal index was chosen in this analysis instead of a Tornqvist index because some utilities do not provide all outputs or use all inputs. A Tornqvist index cannot handle zero quantities.

Fuel and Purchased Power Inputs

The comprehensive TFP measure and the generation TFP measure incorporate fuel inputs, and the comprehensive TFP measure also incorporates purchased power.³ Four fuel inputs are separately recognized including coal, nuclear, natural gas, and oil. Fuel types are inputs into three of the four generation categories including fossil steam, nuclear power, and other power generation. The values of these fuel inputs are observed in the fuel expenses recorded in the electric operation and maintenance report contained in the FERC Form 1 reports.

The prices for these fuel inputs are as follows. A coal price index is assigned to steam generation fuel, a nuclear fuel price index is assigned to nuclear generation fuel, and a composite price index of gas and oil is assigned to other power generation fuel. The composite price index assigns a weight of .97 to the natural gas price index, and .03 to the oil price index. The quantities of fuel for these fuel inputs are obtained by dividing the expense values by the price indexes. A composite quantity index of fuel is derived from a Fisher ideal index of the fuel input quantities.

The value of purchased power is based on purchased power expenses, also as recorded in the FERC Form 1 reports. The price index for purchased power is based on revenue per MWH from sales for resale.

Labor Inputs

For the comprehensive TFP measure, the quantity of labor input is based on the number of employees. The value of labor input equals the total salaries and wages reported for each of the operation and maintenance expense categories, plus reported pension expenses. The price of labor input is obtained by dividing the labor value (expenses, or cost) by the quantity of labor.

To obtain labor input measures for the different operations, the study distributes total labor quantity and value. This is done by developing a distribution key based on the direct payroll, as reported for generation, transmission, distribution, and customer service. This distribution key effectively distributes administrative and general wages and salaries and payroll charged to clearing accounts in proportion to the direct wages and salaries for generation, transmission, distribution, and customer service.

Quasi-Material Inputs

For the comprehensive TFP measure, the value of quasi-materials inputs, which appear in the non-fuel operations and maintenance expenses, is obtained by taking total O&M expenses, subtracting the value of labor, the value of fuel, and the value of purchased power. The price of quasi-materials input is set equal to the Gross Domestic Product Price Index, and the quantity of quasi-materials input is obtained by dividing the value of inputs by the price index.

³ Purchased power must be included in the comprehensive TFP measure since the output measure is based on total sales. Since the generation TFP output measure is based on net generation instead of total sales, it would be inappropriate to include purchased power as an input.

To obtain the value of quasi-materials input for the different operations, we take the O&M expense booked to the operation, plus a share of administrative and general O&M expense, less the value of labor expense for the specific area and, in the case of generation, less the value of fuel and purchased power. The distribution of administrative and general O&M expense is based on the allocation key described in the section on labor input.

Capital Inputs

The value, price, and quantities of capital input are based on the methodology established by Christensen, Gollop, and Stevenson.⁴ Seven capital asset classes are distinguished: steam production, nuclear production, hydro production, other production, transmission plant, distribution plant, and general plant. The first step is to compute quantities of the capital stock using the perpetual inventory method. The perpetual inventory equation assumes the form:

$$K_{it} = I_{it} + (1 - \delta_i) \cdot K_{i,t-1},$$

where K represents the quantity of capital stock, I the quantity of investment, δ the rate of replacement, i the asset class, and t the year. The perpetual inventory equation requires a benchmark (or starting) year and value. 1965 is selected as the benchmark year.

To compute the quantity of investment in each year, the analyses begin by first determining the value of investment, measured in dollars, and the price of investment. The procedure then divides the investment value by the investment price index to obtain the quantity of investment. The value of investment is observed as the additions to plant in service for each asset class, as reported in the FERC Form 1 Report, Electric Plant in Service. The price indexes are based on various Handy-Whitman indexes. The following table shows the mapping of Handy-Whitman indexes to asset classes.

Steam Production Plant	Table E, Line 6 (Total Steam Production Plant)
Nuclear Production Plant	Table E, Line 17 (Total Nuclear Production Plant)
Hydro Production Plant	Table E, Line 22 (Total Hydraulic Production Plant)
Other Production Plant	Table E, Line 28 (Total Other Production Plant)
Transmission Plant	Table E, Line 33 (Total Transmission Plant)
Distribution Plant	Table E, Line 42 (Total Distribution Plant)
General Plant	Table B, Line 2 (Reinforced Concrete Building

⁴ Laurits R. Christensen, Frank M. Gollop, and Rodney Stevenson, "Estimates of Capital Stocks and Capital Services Flows for Privately-Owned Electric Utilities in the U.S., 1950-1975," University of Wisconsin – Madison, May 1980.

	Construction)
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The July price index values of Handy-Whitman are used to represent the capital price level for each year of the analysis. Each utility in the sample is mapped to a Handy-Whitman index region and assigned the set of indexes for that region. The Handy-Whitman indexes are all based to 100 in 1973. The analysis procedure rescales the price indexes to the relative price levels using the Christensen-Gollop-Stevenson scaling factors for 1966. These factors are shown in the following table.

Relative Scaling Factors for Investment Prices in 1966						
Region/Category	1	2	3	4	5	6
Steam (\$/kW)	122.81	119.35	126.26	121.54	126.61	130.08
Nuclear (\$/kW)	176.85	171.86	181.82	175.01	182.32	187.31
Hydro (\$/kW)	221.06	214.83	227.27	218.77	227.90	234.14
Other Production (\$/kW)	83.51	81.16	85.86	82.65	86.10	88.45
Transmission (\$ per circuit miles)	90792.82	88233.07	93343.34	89850.24	93602.09	96161.85
Distribution (\$/customer connection)	1670.25	1623.16	1717.17	1652.91	1721.93	1769.02
General Plant (\$/ft.²)	1.0316	1.0025	1.0606	1.0209	1.0635	1.0926

The replacement rates are based on the 1.5 declining balance method. This means that the replacement rate $\delta_i = 1.5/T_i$, where T_i is the estimated service life of the asset. Following Christensen-Gollop-Stevenson, the study uses the following estimated service lives: steam production plant – 33 years, nuclear production plant – 33 years, hydro production plant – 56 years, other production plant – 24 years, transmission plant – 37 years, distribution plant – 37 years, and general plant – 25 years.⁵

The benchmark values for capital are based on the reported net book values of plant for 1965. The analysis procedure converts the net book values to quantities by using a deflation procedure that accounts for the different vintages of investment goods comprising book value. The net book value, B_i , is obtained by taking the balance at end of year, as reported in the electric plant in service report, and subtracting the end of year balance of accumulated depreciation, reported in the accumulated provision for depreciation of electric utility plant report. The net book value is then divided by a triangularized weighed average of scaled Handy-Whitman values:

⁵ These nominal values for the life of capital should perhaps be reviewed and, if needed, adjusted.

$$K_{i,1965} = \frac{B_{i,1965}}{\sum_{k=1}^{20} \left(\frac{k \cdot HW_{i,1945+i}}{\sum_{k=1}^{20} k} \right)}$$

where HW represents the scaled Handy-Whitman index. The triangularized weighted average approach gives more weight to price index values in more recent years, reflecting the fact that the net book value has more investments of recent vintage.

Once capital stocks are computed for the seven asset classes, the approach is to then compute quantities, prices, and values of capital input. The quantity of capital input (which represents a flow of services during the year) is set to equal the quantity of the capital stock at the end of the previous year:

$$K_{it}^S = K_{i,t-1}.$$

The price of capital input is based on the Christensen-Jorgenson rental price equation:

$$p_{it}^S = \frac{(1 - u_t \cdot z_{it})}{(1 - u_t)} \cdot (r_t \cdot p_{i,t-1} + \delta_i \cdot p_{it} - (p_{it} - p_{i,t-1})) + \tau_t \cdot p_{t-1}$$

where p^S is the implicit rental price, p is the investment price, u is the rate of taxation on corporate income, z is the present value of tax depreciation allowances, r is the after-tax rate of return, δ is the replacement rate used in the perpetual inventory equation (which also equals the rate of economic depreciation), and τ is the rate of property taxation. The study approach simplifies the rental price equation using a method analyzed by Harper, Berndt, and Wood,⁶ which obtains the following conversion of the above equation to:

$$p_{it}^S = \frac{(1 - u_t \cdot z_{it})}{(1 - u_t)} \cdot (\bar{r}_t + \delta_i) \cdot p_{i,t-1} + \tau_t \cdot p_{t-1}$$

where \bar{r} is the real rate of return on capital. We use a 4% real rate of return, which is in line with the range proposed by Harper, Berndt, and Wood. The values of z are based on the MACRS depreciation allowance schedule, while the value of u is set to the marginal federal tax rate of 35%. The property tax rate is computed by dividing reported taxes other than income taxes (found in the statement of income for the year report) by the value of the total capital stock at the end of the year. The value of the capital stock for each asset class is obtained by multiplying the capital stock quantity by the scaled Handy-Whitman index. The total value of capital stock is obtained by adding the values for the seven asset classes.

⁶ Michael J. Harper, Ernst R. Berndt, and David O. Wood, "Rates of Return and Capital Aggregation Using Alternative Rental Prices," in Dale W. Jorgenson and Ralph Landau, eds., Technology and Capital Formation, (MIT Press, 1989), pp. 331-372.

The value of capital input for each asset class is obtained by multiplying the price by the quantity. The quantity of capital input for the comprehensive TFP measure is based on a Fisher ideal quantity index of capital input for the seven asset classes. To obtain capital input measures for each operation, the study approach is to assign the capital inputs to the different operations. Steam production plant, nuclear production plant, hydro production plant, and other production plant are assigned to generation operations. Transmission plant is assigned to transmission operations, while distribution plant is assigned to distribution operation. General plant is distributed to the generation, transmission, distribution, and customer service operations according to the allocation factors described in the section above on labor inputs. Once the capital inputs are assigned to the different operations, they are aggregated using a Fisher ideal quantity index to obtain measures of total capital input.

Determining Total Input

The quantity of total input in the comprehensive TFP measure is computed as a Fisher ideal index of the fuel, purchased power, labor, materials, and capital input quantities. The value of total input is obtained by summing the values of fuel, purchased power, labor, materials, and capital input. The price of total input is obtained by dividing the value by the quantity. The total quantity input measures for the different operations are computed in a similar manner.

Constructing Data for the Electric Industry, and Data Issues

Data used in the immediate study covers those electric utilities that have generation, transmission, and distribution operations. The study begins with 122 utilities that submitted FERC Form 1 reports during the 1994-2004 period,⁷ although reaching back many years the data base consists of well over 200 utilities. Many of these utilities divested themselves of a substantial share of their generation (or transmission) assets during that period, making it difficult to develop comparable capital input measures for those firms. Thus, a number of utilities are excluded from the immediate analysis. Data anomalies are also present for some utilities. While the study work was often able to resolve these anomalies by drawing upon other data sources and estimation methods,⁸ some anomalies could not be resolved leading unfortunately to their exclusion from the immediate study. Finally, a few reporting entities had not reported results for 2004 at the time that the study was performed. The immediate study of U.S. electric utilities covers 55 service providers.

⁷ Some of these firms merged during the study period. In those instances we consolidated their data.

⁸ For example, a couple of firms reported MWh sales for 2004 that were clearly off by an order of magnitude. A close investigation showed that the data reported represented one quarter of sales reported in kWh instead of annual sale reported in MWh. We were able to make corrections for those firms.