

**BEFORE THE
KANSAS CITY BOARD OF PUBLIC UTILITIES**

Prepared Testimony of

Blake L. Elliott

**Energy Rate Component (ERC)
And
Other Rate Issues**

September 7, 2010

Q: PLEASE STATE YOUR NAME AND YOUR BUSINESS ADDRESS.

A: Blake L. Elliott, Board of Public Utilities, 312 N 65th Street, Kansas City, KS 66102.

Q: WHAT IS YOUR POSITION AT THE BPU?

A: I am the Director of Electric Supply Planning.

Q: DID YOU PREVIOUSLY PROVIDE TESTIMONY IN THIS MATTER?

A: Yes, I testified during the rate hearing on May 3 and 4, 2010, and also filed written testimony.

Q: WHAT IS THE PURPOSE OF THE TESTIMONY YOU ARE NOW PROVIDING?

A: The purpose of my testimony is two-fold, first, to provide updates on matters to which I previously testified, and second, to address issues raised by interveners in this proceeding. I have four additional exhibits. (Exhibits BLE-6 through BLE-9)

Q: PLEASE DISCUSS THE ENERGY RATE COMPONENT RIDER AND THE CHANGES THAT BPU HAS MADE FROM THE ORIGINAL RECOMMENDATION.

A: The revised ERC Rider is submitted with this testimony as Exhibit BLE-9. Below, please find a summary of staff's recommendations on the major changes in The Energy Rate Component (ERC) Rider revised from the originally proposed ERC:

1. Within the definition of Power supply costs, BPU will recognize two types of purchased power contracts that supply Capacity to the BPU:
 - a. Long-term Purchase Power which is a purchase power contract, with a Demand or Capacity price component, with a term that is greater than one year in length.
 - b. Short-term Purchase Power which is a purchase power contract, with a Demand or Capacity price component, with a term that is less than one year in length.

2. Long-term Purchase Power Demand or Capacity charges will be removed from the proposed ERC and placed back into the Base Rates up to a maximum annual amount equal to the sum of the known Long-term Purchase Power Demand or Capacity charges at the time of the current Base Rate adjustment through the rate hearing process, which is presently \$2.6 million annualized. Any excess amount due to either, cost adjustments to existing contracts or the addition of new Long-term Purchase Power contracts will be rolled over into the ERC until the next Base Rate adjustment through the rate hearing process. This is similar to a rate structure used

by another municipal utility in the metropolitan area, Independence Power & Light, in its Fuel-Energy Cost Adjustment.

3. Demand or Capacity charge costs related to Short-term Purchase Power will be recovered in ERC Rider.
4. Demand or Capacity charge costs related to transmission will be recovered in ERC Rider as proposed.

Q: PLEASE EXPLAIN HOW THIS ERC METHODOLOGY WILL AFFECT THE ERC.

A: The effect should be minimal. At the current time a similar amount is being applied to base rates. The amount of demand or capacity charges immediately following a Base Rate Hearing will be zero. Over time it will increase slowly due to the escalation of existing contract, execution of new long-term and short-term purchase power contracts. New and existing long-term contract capacity charges will be zeroed out at the next rate hearing and short-term purchase power capacity charges will be zeroed out when BPU adds new long-term capacity or adds generation as determined by economic modeling. BPU does not expect the amount of Demand or Capacity charges in the ERC to be material in most years.

Q: COULD YOU EXPLAIN FURTHER BPU'S REASONS FOR THESE CAPACITY RELATED CHANGES AND WHAT RATE MAKING PRINCIPLES HAVE GUIDED STAFF TO THESE CONCLUSIONS?

A: BPU staff understands the intervener's bias toward shifting costs away from energy charges which yields a benefit to the customers they represent. In testimony provided by Robert Stephens he explains a traditional commission's philosophy for the existence of a fuel adjustment clause in a regulated environment.

"By their nature, fuel adjustment clauses such as the ERC rider traditionally have been used for recovery of large, volatile costs such as fuel costs, since fuel costs: 1) have a large impact on the utility's overall cost structure; 2) can vary widely and sometimes without warning; and 3) are generally beyond the utility's control."

In a highly regulated electric utility environment dominated by large Investor Owned Utilities (IOUs) with adequate capacity resources the definition provided by the interveners might be enough. However, in the market driven environment BPU finds itself in today it is inadequate. Purchase power prices charged in a market driven electric utility environment are based on whatever the market will bear with discussions between buyer and seller including how much cost will be placed in capacity and how much in

energy. BPU is not an IOU, it is a Municipal. By statute it can't make a profit so unknown, extra or intermittent costs can't come from stock holders. Neither are there large reserve funds to support these types of expenses.

Q: PLEASE EXPLAIN THE TYPES OF CAPACITY OR DEMAND CHARGES THAT WILL BE RECOVERED THROUGH THE ERC.

A: There are three types of capacity or demand charges that would be recovered through the ERC in BPU's current proposed ERC language.

- 1) Long-term generation capacity payments that are known at the time of the most recent rate hearing will be recovered in the base rates. So by exclusion, if a long-term purchase power contract is entered into between rate hearings and the capacity payments begin between rate hearings, than all of the capacity payments before the effective date of the next rate setting event are recoverable through the ERC. Further more if one of BPU's Long-term purchase power contracts experienced a price increase between rate hearings, the amount above the portion in base rates will be recoverable through the ERC until the next rate setting event at which time these charges will be moved into Base Rates zeroing out their contribution to the ERC.

- 2) Short-term purchase power capacity to meet BPU's Southwest Power Pool Capacity Planning Margin will be recovered through the ERC. When looking at the next two or three summer periods BPU is forecasting that there will not be a need for short-term capacity due to the economy related decrease in load and its associated capacity requirement and the increase in capacity due to acquisition of firm transmission for its Southwestern Power Administration's hydro allocation, effective July 1 2010. With that said, BPU's capacity planning margin is very near the SPP's minimum requirement of 12%. With slight improvements in the economy BPU could be in a position that requires the purchase of short-term capacity at a price as volatile as other fuel components in the ERC. If BPU is unable to recover short-term and other unknown capacity costs through the ERC than Base rates will need to absorb the costs. Since no costs were put into the Revenue Requirement portion of this study, the payment of capacity will use money allocated for other critical utility infrastructure and programs. The argument that some expenses will be less than estimated and some will be more using a fixed escalation factor and the extra money from the lower than estimated expenses will pay for these short-term, unknown and unexpected capacity charges is simply not true. The magnitude of these capacity charges will be too great to be recovered by any reasonable forecast error.

3) Transmission demand or capacity charges purchased from the SPP exists more in theory than reality. Since the advent of open access transmission with Federal Energy Regulatory Commission (FERC) Order #888 there have been major changes to the way transmission is owned and its access sold and invoiced. Traditional bi-lateral transmission contracts contained a capacity charge, an energy charge and other types of ancillary service fees. These fees would be broken out on the invoice that covered the monthly transmission service. Today transmission is sold, scheduled and invoiced through the Southwest Power Pool (SPP) which invoices transmission purchasers for multiple transmission purchases, losses and services fees with daily amounts that can't be readily traced back to any known or knowable capacity charge. A copy of a typical SPP invoice is included for reference (Exhibit BLE-6). Removing the wording of capacity transmission payments from the ERC language is recognition of the current state of transmission not a change in philosophy or policy. In fact, many SPP transmission owners have adopted formula rates for transmission. These formula rates are approved by the Federal Energy Regulatory Commission and change annually thus increasing volatility.

Q: ARE OTHER UTILITIES RECOVERING THESE TYPES OF DEMAND AND CAPACITY CHARGES THROUGH THEIR FUEL ADJUSTMENT CLAUSES?

A: Yes. BPU has reviewed the fuel adjustment clause of Independence Power & Light, Independence, Missouri, in its rider FA-1 Power Supply Fuel-Energy Cost Adjustment dated January 1, 2006 (Exhibit BLE-7) comparing it to the same rider dated July 1, 2009 (Exhibit BLE-8). Two major changes that can be seen in the 2009 version the first is the inclusion of a fixed dollar amount of demand or capacity charge related to purchase power expenses allocated to base rates with the excess being included in the fuel adjustment clause. The second is the word demand or capacity as it relates to transmission charges is omitted. Municipal utilities which are typically smaller and may not be regulated by a public utility commission have an advantage over much larger IOUs that are regulated by a state utility commission that being, the municipal utility is not a bureaucracy governed by another bureaucracy. Change can occur more rapidly than might otherwise happen, especially when that change is related to the critical cash flow required to cover utility costs.

Q: WHY SHOULD DEMAND RESPONSE COSTS, WHICH GIVE THE UTILITY DIRECT CONTROL OF CUSTOMER LOAD FOR PEAK SHAVING, NOT OTHERWISE RECOVERED BE INCLUDED IN THE ERC?

A: In my previous testimony I detailed why Demand Response costs should be included in the ERC. However, two points within my previous testimony warrant an update and further explanation. In the original version of the ERC the language was similar to the wording in the question above. BPU was advocating "Direct Control of customer load." After discussion with the Interveners, BPU decided that a better description for what BPU is trying to accomplish is Dispatchable Control of customer load. This provides stricter limits on the types of Demand Response programs which are recoverable through the ERC. Furthermore, in the case of Demand Response program costs recovered in BPU's ERC the emphasis should be on the final provision which reads, "not otherwise recovered." This allows BPU to initiate small pilot programs that will benefit all customer classed by identifying Demand Response programs that may forestall the addition of generation. When a Demand Response program proves its savings the associated costs will be rolled into the base rates at the next rate hearing. Allowing program start-up costs pass through the ERC allows BPU to do the right thing within tight budget constraints.

Q: **WITH THESE CHANGES IN PLACE WHAT IS THE VALUE OF THE CAPACITY PAYMENTS THAT ARE BEING MOVED INTO THE BASE RATES DURING THIS RATE SETTING EVENT?**

A: At the current time BPU is proposing to move \$2.6 million of known Long-term capacity charges into the base rates from the ERC. This reallocation of expenses is without any increase to the base rate proposal of four annual 7% increases in the revenue requirement. Further details about adjustments made to the revenue requirement can be found in other testimony by BPU staff and or Black & Veatch Consulting, filed on this date.

Q: **HAVE THE CHANGES IN THE ERC BEEN DISCUSSED WITH THE INTERVENERS?**

A: Yes. The BPU has been in discussions with the Industrial Interveners concerning the ERC and has proposed changes outlined above to the language of the ERC Rider of which the interveners are aware. The update should alleviate some concerns expressed by the interveners in the testimony of Robert Stephens when he writes:

"If capacity related charges become significant items in the ERC rider, this will create perverse planning incentives for the utility and will result in shifting of cost responsibility between customers and classes."

BPU staff does not expect capacity related charges to be a significant portion of the ERC since known long-term capacity will be included in base rates and incremental capacity charges will be rolled over to the base rates at each rate setting event.

Q: THE INTERVENER SET FORTH AN ALTERNATE PROPOSAL IF THEIR RECOMMENDATION TO PREVENT INCREMENTAL CAPACITY FROM PASSING THROUGH THE ERC NOT BE ADOPTED. WHAT IS STAFF'S RECOMMENDATION ON THIS MATTER?

A: The interveners have recommended that if any capacity is recovered in the ERC than the ERC should be reduced by incremental margins the BPU receives for off-system sales. There are two points at issue here. The first is that it makes the ERC calculation and its reconciliation much more difficult. The second is more related to the balance of BPU's loads and resources. BPU is a net buyer of energy in the wholesale market. In most years we sell little energy and receive limited margin on those sales. Of the margin received it is included in the calculation for revenue requirements. That money is being used to hold down the amount needed to fund the utilities base rates from our retail customers. Occasionally if retail sales are below forecast than BPU may have excess generation resources to sell into the market. If the market price is favorable for sales in a given hour when we have excess generation and if there is adequate transmission to allow those sale to occur than it appears on the surface that wholesale sales are up BPU is making "extra" money. That is an incomplete picture of the situation. When wholesale sales are up it is because retail sales are down and we have excess generation to sell in the market. By making this sale we are allowing the utility to benefit from more wholesale sales in light of less retail sales. In essence wholesale sales are acting as a partial natural hedge against low retail sales. That is assuming that BPU's excess generation will be priced favorably to the market price and that transmission is available to allow the transaction to flow electricity. Contrary to the view asserted by Mr. Stephens, the BPU has no incentive to, and would not procure off-system generation in order to make greater off-system sales.

Q: WHAT SAFEGUARDS ARE IN PLACE TO PREVENT THE PERVERSE PLANNING INCENTIVES ALLUDED TO BY THE INTERVENER'S TESTIMONY IF INCREMENTAL CAPACITY IS ALLOWED TO PASS THROUGH TO THE CUSTOMERS THROUGH THE ERC?

A: The BPU is a public power utility. Management staff has a great deal of experience and history managing a public utility. The management team under the direction of the General Manager present major decisions to the elected Board for informational updates as well as for approval when required. The Board hires the General Manager to manage the utility in accordance with Board Policy. The Board also approves the annual Budget. The Board is responsible to the citizens who are the customers and community of BPU.

Community citizens have a direct and powerful voice in utility decisions and policies, both at the ballot box and in open meetings where business is conducted.

Q: DOES THIS CONCLUDE YOUR ADDITIONAL TESTIMONY ON THE ENERGY RATE COMPONENT AS IT APPLIES TO THE CURRENT RATE HEARING?

A: Yes.

Q: ARE THERE ANY OTHER ISSUES RAISED BY INTERVENERS IN THIS PROCEEDING THAT YOU WOULD LIKE TO ADDRESS?

A: Yes. I would like to comment about the comparison of Industrial rates used by Mike Gorman in his testimony. Table 1 appears to be purposely selective in its choice of utilities, restrictive in its choice of only the Industrial customers and the short time frame used, five years. This methodology allows for a very small portion of the picture to be shown. All of the utilities chosen for comparison to the BPU in this table are large IOU's. Two of the three utilities that make up KCP&L were chosen but not the portion most recently acquired in the buy-out of Aquilla. KCP&L serves a total of 820,000 electric customers. Westar in its two price zones serves 685,000 customers. BPU serves 65,000 electric customers. Each of the two utilities chosen in the metro area is greater than ten times the size of BPU. There is one other Municipal in the metropolitan area. Independence Power & Light that was not chosen for comparison by the interveners which serves 50,000 electric customers. Large IOUs will have different economies of scale, a different resource mix which may include low cost nuclear, a different customer mix, and most certainly a different cost structure when looking at a utility that covers a large geographical area with rural and urban areas. The point is that if you just look at one part of the puzzle you don't see the full picture.

I am including in this testimony four tables and graphs that look at each of the three major customer classes individually, Residential, Commercial and Industrial plus the total of those three for a more complete picture of the BPU compared to other utilities. I have compared BPU to 13 utilities not five. I have added some municipal utilities to capture additional diversity of size and type of utility. Two of the 13 utilities are home to sister plants of Griffin Wheel for Industrial price comparison. I have compiled 10 years of data instead of five to see how each of the utilities handled deregulation and market price spikes in previous years. Finally you can see by comparison in each individual company where each utility's costs are assuming that its rates reflect true cost of service by customer class. No utility is ever at true cost of service but over time you can see a shift

downward from one class that is over recovering to an upward shift in another class that is under recovering as attempts are made to move to cost of service.

Additional information worth noting on each table is that the farthest right hand column is the BPU Revenue/Consumption value of each year compared to the average of all of the other 13 utilities being compared. All customer class and total graphs are scaled the same so that the reader can get the sense of which class sees higher and lower values of Revenue/Consumption values by where the cluster of lines appear on each graph. BPU appears near the middle of each customer class and the total graph, although there are slight variations by year which can be attributed to fuel cost adders and timing of rate adjustments between utilities. Prior to the first table and graph is a key which provides additional information about the data in the tables and graphs.

KEY for Class Revenue/Consumption Figures

BPU KCK	Kansas City Kansas Board of Public Utilities (KS)
WestarKG&E	Westar Southern Zone (Kansas Gas & Electric) (KS)
MWE	Midwest Energy (KS)
Westar	Westar Norther Zone (Western Resources) (KS)
KCPL KS	Kansas City Power & Light Kansas (KS)
EDE KS	Empire District Electric Kansas (KS)
EDE MO	Empire District Electric (MO)
Indep	Independence Power & Light Independence, (MO)
KCPL MO	Kansas City Power & Light Kansas (MO)
KCPL/GMO Aquila MO	Kansas City Power & Light Kansas (Aquila) (MO)
CU Spring	City Utilities Springfield (MO)
MidAm Energy IA	Mid American Energy (IA)
Aliant ISP&L IA	Alliant Energy Interstate Power & Light (IA)
AEP CoIso OH	AEP Columbus Southern (OH)

Used for comparison by Mike Gorman in Table 1

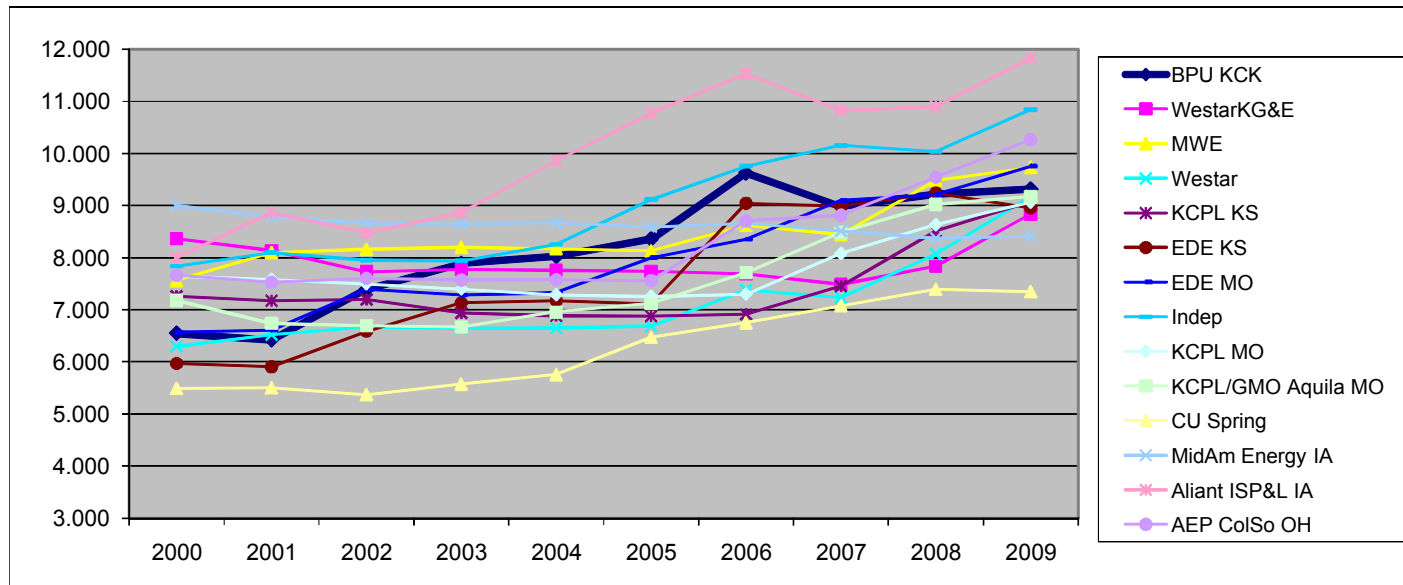
Utilities of Griffin Wheel Sister Plants

Notes:

All data taken from EIA 861 report when available and EIA 826 report after EIA 861 was discontinued
 Customer Class Revenue divided by Energy

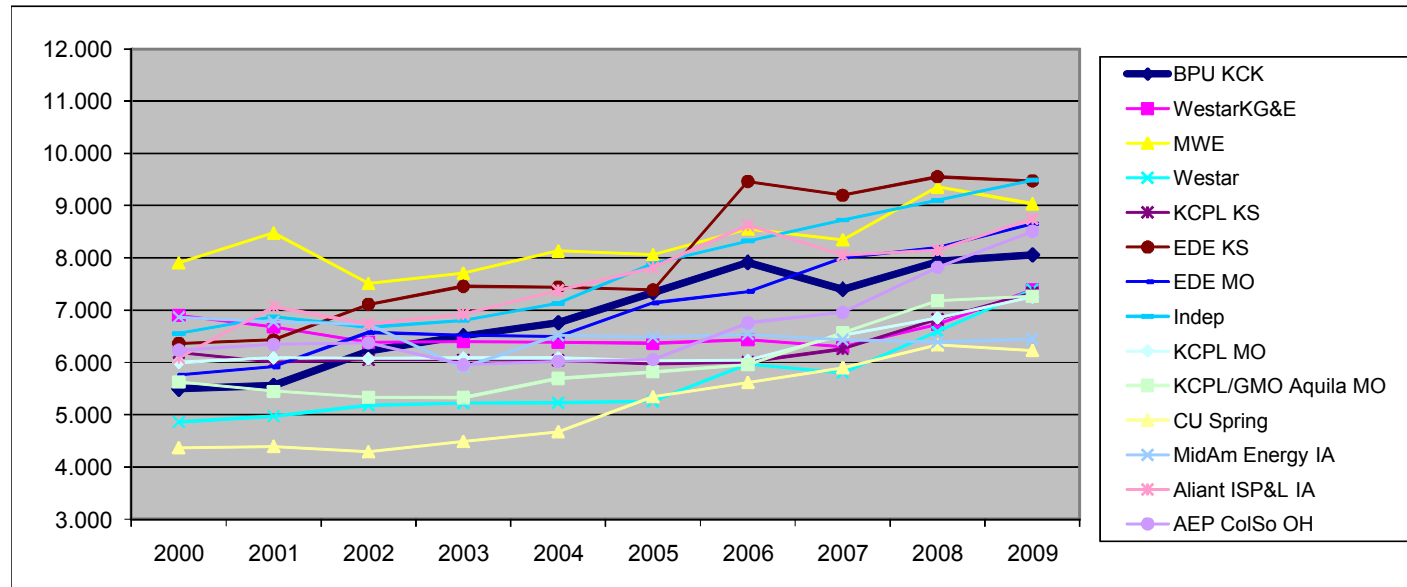
Residential Revenues/Consumption in ¢/kWh

	BPU KCK	Westar KG&E	MWE	Westar	KCPL KS	EDE KS	EDE MO	Indep	KCPL MO	KCPL/ GMO Aquila MO	CU Spring	MidAm Energy IA	Aliant ISP&L IA	AEP ColSo OH	BPU Percent of Average
2000	6.548	8.361	7.562	6.297	7.260	5.969	6.570	7.833	7.644	7.180	5.488	8.995	7.999	7.659	90.4%
2001	6.422	8.136	8.097	6.524	7.175	5.908	6.610	8.100	7.583	6.739	5.500	8.779	8.865	7.528	88.2%
2002	7.390	7.729	8.161	6.668	7.195	6.590	7.392	7.953	7.496	6.699	5.371	8.666	8.473	7.603	100.1%
2003	7.888	7.773	8.199	6.649	6.941	7.138	7.282	7.937	7.399	6.673	5.573	8.648	8.864	7.571	105.6%
2004	8.029	7.755	8.170	6.652	6.886	7.172	7.328	8.252	7.288	6.959	5.758	8.672	9.859	7.578	105.7%
2005	8.353	7.739	8.128	6.688	6.879	7.116	8.001	9.116	7.256	7.122	6.472	8.592	10.775	7.557	106.5%
2006	9.626	7.692	8.619	7.381	6.914	9.044	8.351	9.759	7.300	7.715	6.750	8.658	11.530	8.705	114.2%
2007	8.981	7.489	8.446	7.237	7.453	8.986	9.098	10.153	8.079	8.491	7.080	8.514	10.827	8.813	105.1%
2008	9.218	7.840	9.487	8.069	8.510	9.242	9.209	10.034	8.631	9.023	7.394	8.370	10.899	9.546	102.9%
2009	9.313	8.837	9.733	9.167	9.071	8.959	9.758	10.840	9.066	9.171	7.348	8.417	11.822	10.264	99.0%
	Intervenor's Comparisons					Utilities Serving Griffin Wheel Sister Plants									



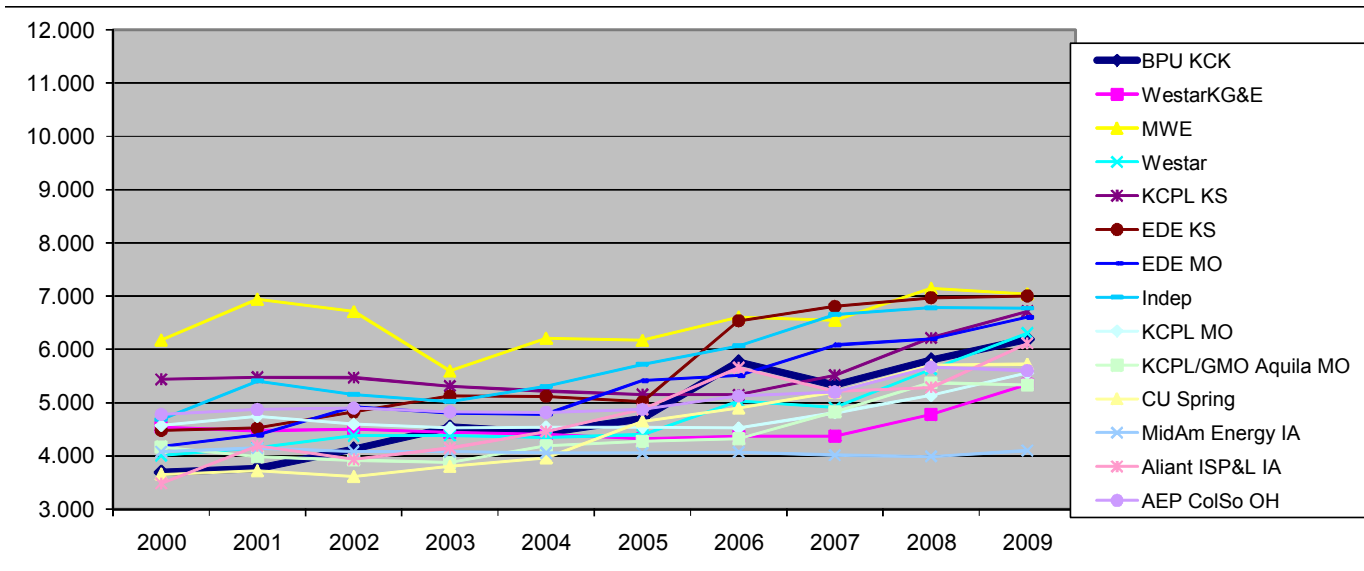
Commercial Revenues/Consumption in ¢/kWh

	BPU KCK	Westar KG&E	MWE	Westar	KCPL KS	EDE KS	EDE MO	Indep	KCPL MO	KCPL/ GMO Aquila MO	CU Spring	MidAm Energy IA	Aliant ISP&L IA	AEP ColSo OH	BPU Percent of Average
2000	5.494	6.905	7.907	4.864	6.191	6.365	5.759	6.555	6.002	5.625	4.366	6.869	6.093	6.234	90.2%
2001	5.563	6.683	8.477	4.973	6.011	6.431	5.916	6.877	6.090	5.450	4.395	6.776	7.068	6.347	89.5%
2002	6.215	6.386	7.513	5.180	6.052	7.112	6.575	6.673	6.074	5.334	4.290	6.724	6.736	6.375	99.7%
2003	6.511	6.398	7.708	5.217	6.053	7.459	6.516	6.805	6.087	5.328	4.484	5.901	6.925	5.958	104.3%
2004	6.761	6.383	8.134	5.230	6.043	7.444	6.496	7.132	6.086	5.696	4.673	6.520	7.377	6.021	105.2%
2005	7.339	6.370	8.063	5.262	5.977	7.390	7.139	7.888	6.032	5.821	5.344	6.489	7.814	6.055	110.5%
2006	7.913	6.439	8.553	5.967	6.010	9.462	7.359	8.323	6.039	5.959	5.615	6.539	8.630	6.760	111.3%
2007	7.400	6.299	8.348	5.804	6.260	9.198	8.008	8.725	6.520	6.571	5.897	6.436	8.053	6.959	103.1%
2008	7.930	6.729	9.357	6.589	6.824	9.554	8.201	9.101	6.853	7.181	6.333	6.392	8.146	7.818	103.7%
2009	8.055	7.396	9.039	7.391	7.331	9.475	8.649	9.487	7.253	7.271	6.230	6.447	8.743	8.509	101.3%
	Intervenor's Comparisons					Utilities Serving Griffin Wheel Sister Plants									



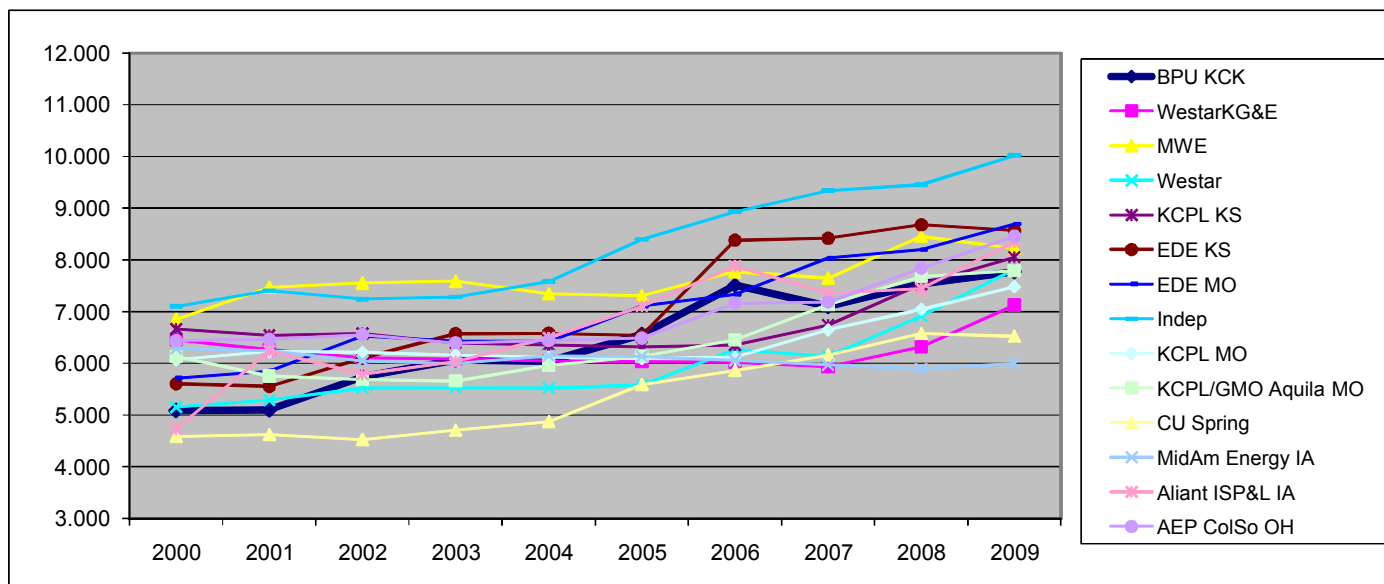
Industrial Revenues/Consumption in ¢/kWh

	BPU KCK	Westar KG&E	MWE	Westar	KCPL KS	EDE KS	EDE MO	Indep	KCPL MO	KCPL/ GMO Aquila MO	CU Spring	MidAm Energy IA	Aliant ISP&L IA	AEP ColSo OH	BPUPercent of Average
2000	3.690	4.541	6.170	4.008	5.436	4.481	4.183	4.680	4.569	4.160	3.654	4.075	3.482	4.778	83.5%
2001	3.762	4.472	6.939	4.152	5.478	4.523	4.388	5.408	4.741	3.980	3.720	4.146	4.189	4.870	81.3%
2002	4.130	4.502	6.708	4.379	5.467	4.823	4.921	5.153	4.593	3.920	3.612	4.082	3.935	4.898	88.8%
2003	4.539	4.437	5.590	4.386	5.314	5.122	4.801	5.024	4.520	3.882	3.801	4.076	4.148	4.827	98.6%
2004	4.435	4.403	6.206	4.346	5.214	5.119	4.786	5.302	4.540	4.188	3.957	4.057	4.455	4.819	94.3%
2005	4.703	4.319	6.166	4.399	5.155	5.015	5.413	5.723	4.536	4.276	4.652	4.055	4.872	4.873	96.6%
2006	5.764	4.365	6.608	5.026	5.148	6.537	5.506	6.064	4.521	4.321	4.898	4.070	5.655	5.125	109.6%
2007	5.330	4.368	6.549	4.909	5.517	6.803	6.079	6.657	4.808	4.821	5.199	4.013	5.208	5.197	98.9%
2008	5.797	4.780	7.149	5.624	6.213	6.970	6.196	6.780	5.135	5.372	5.700	3.988	5.289	5.669	100.6%
2009	6.190	5.340	7.042	6.307	6.715	7.003	6.602	6.770	5.552	5.334	5.719	4.099	6.113	5.601	102.7%
Intervenor's Comparisons					Utilities Serving Griffin Wheel Sister Plants										



Total Revenues/Consumption in ¢/kWh

	BPU KCK	Westar KG&E	MWE	Westar	KCPL KS	EDE KS	EDE MO	Indep	KCPL MO	KCPL/ GMO Aquila MO	CU Spring	MidAm Energy IA	Aliant ISP&L IA	AEP ColSo OH	BPU Percent of Average
2000	5.091	6.450	6.853	5.155	6.667	5.605	5.718	7.103	6.068	6.130	4.590	6.284	4.732	6.439	86.0%
2001	5.103	6.261	7.473	5.290	6.541	5.557	5.849	7.406	6.228	5.755	4.624	6.242	6.249	6.463	84.0%
2002	5.739	6.105	7.550	5.521	6.580	6.101	6.531	7.243	6.213	5.691	4.526	6.044	5.791	6.554	93.2%
2003	6.060	6.080	7.588	5.529	6.399	6.574	6.429	7.283	6.163	5.659	4.708	5.990	6.035	6.399	97.6%
2004	6.042	6.045	7.341	5.521	6.351	6.584	6.423	7.583	6.120	5.960	4.875	6.149	6.495	6.441	96.2%
2005	6.557	6.031	7.306	5.583	6.320	6.540	7.106	8.399	6.101	6.137	5.591	6.136	7.105	6.487	100.4%
2006	7.512	6.021	7.771	6.271	6.351	8.379	7.340	8.932	6.118	6.454	5.861	6.063	7.883	7.162	107.2%
2007	7.100	5.935	7.648	6.134	6.744	8.419	8.033	9.339	6.649	7.131	6.162	5.973	7.356	7.187	99.6%
2008	7.538	6.321	8.453	6.916	7.528	8.678	8.198	9.452	7.044	7.679	6.576	5.894	7.447	7.842	100.0%
2009	7.775	7.126	8.224	7.817	8.054	8.567	8.692	10.020	7.479	7.793	6.524	5.997	8.347	8.457	98.2%
Intervenor's Comparisons					Utilities Serving Griffin Wheel Sister Plants										



Q: ARE THERE ANY OTHER ISSUES RAISED BY INTERVENERS IN THIS PROCEEDING THAT YOU WOULD LIKE TO ADDRESS?

A: Yes. There is one by Mr. Stephens and one by Mr. Gorman. Mr. Stephens raises the issue of the BPU's proposal to expand the summer daily demand measurement period from a 10 hour period of 10:00 a.m. to 8:00 p.m. to a 13 hour period of 10:00 a.m. to 11:00 p.m. At the current time the BPU recognizes that some larger customers have made changes to their usage patterns to minimize their peak demand during the current 10 hour period thus reducing their associated demand charges. Black & Veatch made their recommendation to extend this period based on a study of the wholesale market energy price patterns. The BPU is modifying its original proposal and is willing to keep the current summer demand period pending further study. This study will cover usage patterns by customers who may participate in pilot studies on Time of Use rates.

Mr. Gorman made a recommendation that rate increases not extend beyond 2011 due in part to the inability of forecasts to capture true revenue requirements beyond a one or two year window. Many utilities act on multiple year rate increases especially among municipal utilities and BPU's Board has specifically requested that staff recommend multiple year rate increases rather than a large rate increases every few years. The BPU feels that multiple year small increases are preferred by our customers so that they can make adjustments into their budgets gradually.

Q: IN YOUR POSITION AS DIRECTOR OF ELECTRIC SUPPLY PLANNING IS THERE ANY OTHER INFORMATION NOT RELATED TO TESTIMONY OF THE INTERVENERS WHICH MAY PROVE BENEFICIAL IN THIS MATTER?

A: As a final graphic, on following page, I would like to share a comparison of BPU's base rates going back to 1984 compared to the Kansas City Metropolitan Area Consumer Price Index. What this shows is the comparison of buying a basket of goods that an urban consumer in the Kansas City Metro area would need which cost \$100 in 1984 would cost about \$195 in 2010 while \$100 of BPU electricity purchased in 1984 could be purchased for \$140 today. BPU's base rates have not kept pace with inflation. We do feel our customer's pain due to the difficult economy. We may even feel it more acutely due to our current lag in rate increases compared to CPI, but the safe, reliable and low cost energy that BPU provides is worth the investment.

Q: DOES THIS CONCLUDE YOUR ADDITIONAL TESTIMONY AS IT APPLIES TO THE CURRENT RATE HEARING?

A: Yes.

BPU Cumulative Electric Base Rate vs. KC Metro Consumer Price Index (1984 Basis)

