Exhibit No.:	
Issues:	System Energy Losses Jurisdictional Allocations
Witness:	Alan J. Bax
Sponsoring Party:	MO PSC Staff
Type of Exhibit:	Direct Testimony
Case No.:	ER-2004-0570
Date Testimony Prepared:	September 20, 2004

MISSOURI PUBLIC SERVICE COMMISSION

UTILITY OPERATIONS DIVISION

DIRECT TESTIMONY

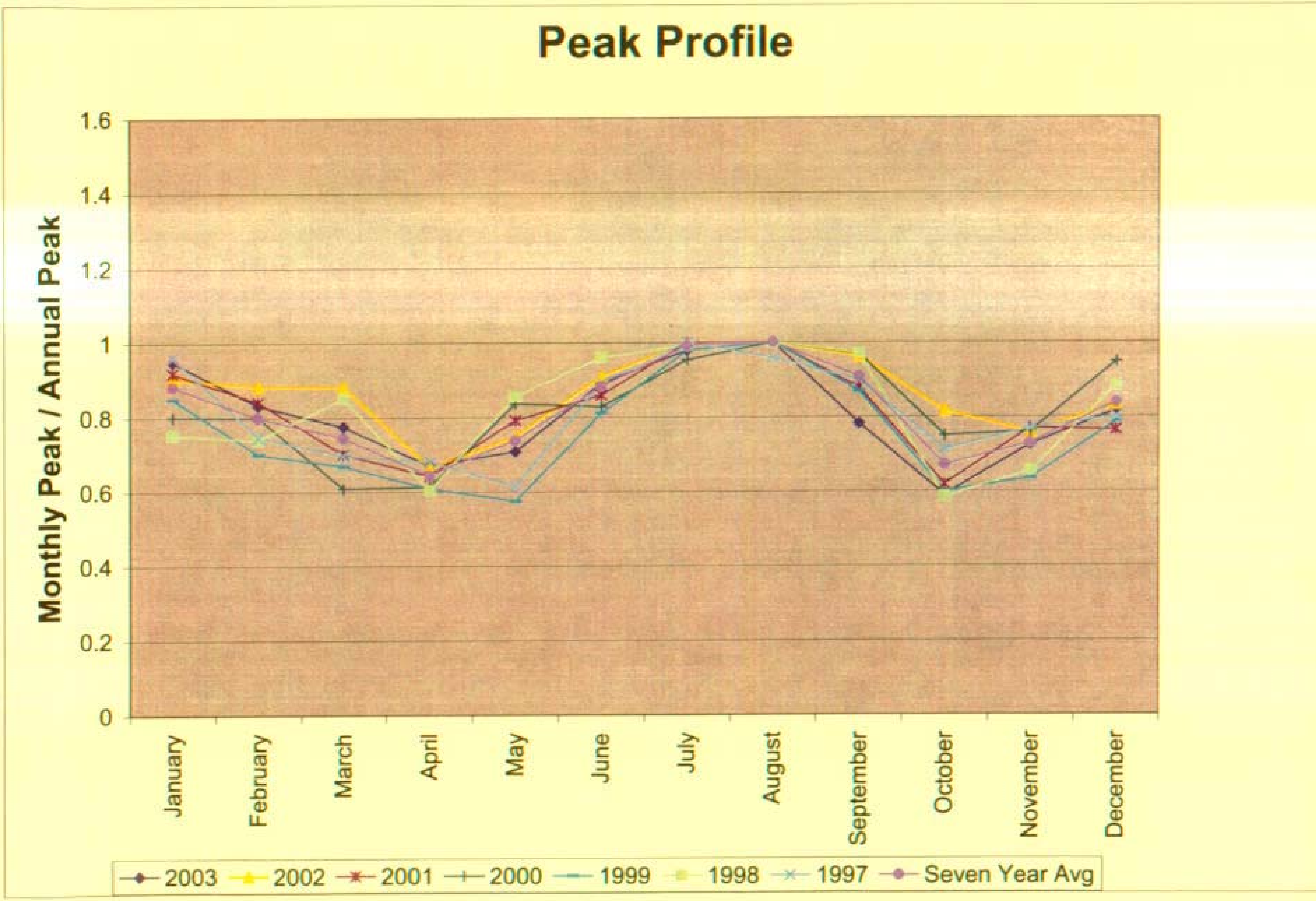
OF

ALAN J. BAX

EMPIRE DISTRICT ELECTRIC COMPANY

CASE NO. ER-2004-0570

Jefferson City, Missouri
September 2004


Peak Profile
Monthly Peak / Annual Peak
1.6
1.4
1.2
1
0.8
0.6
0.4
0.2
0
January
February
March
April
May
June
July
August
September
October
November
December
2003
2002
2001
2000
1999
1998
1997
Seven Year Avg

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of the tariff filing of The Empire District Electric Company to implement a general rate increase for retail electric service provided to customers in its Missouri service area.	))))	Case No. ER-2004-0570

AFFIDAVIT OF ALAN BAX

STATE OF MISSOURI)
) **ss**
COUNTY OF COLE)

Alan Bax, of lawful age, on his oath states: that he has participated in the preparation of the following Direct Testimony in question and answer form, consisting of 12 pages of Direct Testimony to be presented in the above case, that the answers in the following Direct Testimony were given by him; that he has knowledge of the matters set forth in such answers; and that such matters are true to the best of his knowledge and belief.

Alan Bax
Alan Bax

Subscribed and sworn to before me this 16th day of September, 2004.

Dawn L. Hake
Notary Public

My commission expires DAWN L. HAKE Notary Public – State of Missouri County of Cole My Commission Expires Jan 9, 2005

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DIRECT TESTIMONY

OF

ALAN J. BAX

EMPIRE DISTRICT ELECTRIC COMPANY

CASE NO. ER-2004-0570

Q. Please state your name and business address?

A. Alan J. Bax, P.O. Box 360, Jefferson City, Missouri, 65102.

Q. By whom are you employed and in what capacity?

A. I am employed by the Missouri Public Service Commission (Commission) as a Utility Engineering Specialist III in the Energy Department of the Utility Operations Division.

Q. Please describe your educational and work background.

A. I graduated from the University of Missouri - Columbia with a Bachelor of Science degree in Electrical Engineering in December 1995. Concurrent with my studies, I was employed as an Engineering Assistant in the Energy Management Department of the University of Missouri – Columbia from the Fall of 1992 through the Fall of 1995. Prior to this, I completed a tour of duty in the United States Navy, completing a course of study at the Navy Nuclear Power School and a Navy Nuclear Propulsion Plant. Following my graduation from the University of Missouri - Columbia, I was employed by The Empire District Electric Company (Empire or Company) as a Staff Engineer until August 1999, at which time I began my employment with the Staff of the Missouri Public Service Commission (Staff).

Q. Are you a member of any professional organizations?

A. Yes, I am a member of the Institute of Electrical and Electronic Engineers (IEEE).

Q. Have you previously filed testimony before the Commission?

A. Yes. Please refer to Schedule 1 for a list of cases.

Q. What is the purpose of your testimony?

A. The purpose of this testimony is to recommend that the Commission adopt the system energy loss factor and the jurisdictional allocation factors for demand and energy that I calculated as shown on Schedules 2, 7, and 8 respectively, attached to this Direct Testimony. My testimony also describes how I determined these factors.

SYSTEM ENERGY LOSS FACTOR

Q. What is the result of your system energy loss factor calculation?

A. As shown on Schedule 2 attached to this direct testimony, I have calculated the system energy loss factor to be 0.0718 of Net System Input (NSI).

Q. What are system energy losses?

A. System energy losses are the energy losses that occur in the electrical equipment (e.g., transmission and distribution lines, transformers, etc.) in Empire's system between the generating sources and the customers' meters.

Q. How are system energy losses determined?

A. The basis for this calculation is that NSI equals the sum of "Total Sales," "Company Use," and "System Energy Losses." This can be expressed mathematically as:

NSI = Total Sales + Company Use + System Energy Losses

NSI, Company Use and Total Sales are known; therefore, system energy losses may be calculated as follows:

System Energy Losses = NSI – Total Sales – Company Use

The system energy loss factor is the ratio of system energy losses to NSI:

System Energy Loss Factor = System Energy Losses ÷ NSI

Q. How is NSI determined?

A. In addition to the equation above, NSI is also equal to the sum of Empire's net generation and net interchange. Net interchange is the difference between interchange purchases and off-system sales. Net generation is the total energy output of each generating station minus the energy consumed internally to enable its production. The output of each generating station is monitored continuously, as is the net of off-system purchases and sales. I obtained this information from data supplied by Empire in response to Staff Data Request Nos. 109, 148, and 149.

Q. What are Total Sales and Company Use and how are these values determined?

A. Total Sales includes all of Empire's retail and wholesale sales of energy.Company Use is the electricity consumed at Empire's non-generation facilities, such as its corporate office building at 620 Joplin Street. Total Sales data was provided by Empire in response to Staff Data Request No. 146. Company Use data was provided by Empire in response to Staff Data Request No. 147.

Q. Is the difference between NSI and total sales, other than company use, due solely to energy losses?

A. The difference between NSI and total sales, other than company use, is predominantly due to energy losses but not entirely. Included in this difference is a small fraction attributed to diversion (energy stolen), and another minute amount is unmetered. Another fractional difference is also caused by the fact that NSI data is provided by calendar month and total sales data provided by billing month.

Q. Which Staff witness used your calculated system energy loss factor?

B. I provided my calculated system energy loss factor to Staff witness Richard J. Campbell.

JURISDICTIONAL ALLOCATIONS

Q. Please define the phrase "jurisdictional allocation".

A. For purposes of my testimony, jurisdictional allocation refers to the process by which demand-related and energy-related costs are allocated to the applicable jurisdictions. In this case, demand-related and energy-related costs are divided among three jurisdictions: Missouri retail operations, non-Missouri retail operations and wholesale operations. The particular allocation factor applied is dependent upon the types of costs being allocated.

DEMAND ALLOCATION FACTOR

Q. What are the demand allocation factors that you are recommending be used in this case?

A. As shown on Schedule 7 attached to this Direct Testimony, the calculated demand allocation factors for the test year are as follows:

Missouri Retail	0.8195

Non-Missouri Retail	0.1164
Wholesale	0.0641

Q. What is the definition of demand?

A. Demand refers to the rate at which electric energy is delivered to or by a system, generally expressed in kilowatts (kW) or megawatts (MW), either at an instant in time or averaged over any designated interval of time. In my analyses, I used hourly demands.

Q. What types of costs are allocated on the basis of demand?

A. Capital costs associated with generation and transmission plant and certain operational and maintenance expenses are allocated on this basis. This is appropriate for these expenses because generation and transmission are planned, designed and constructed to meet anticipated demand.

Q. What methodology did you use to determine the demand allocators?

A. I used what is known as the Twelve Coincident Peak (12 CP) methodology.

Q. What is meant by the twelve coincident peak methodology?

A. The term coincident peak refers to the load, in megawatts (MWs), of each jurisdiction that coincides with the hour of Empire's overall system peak. A 12 coincident peak methodology refers to utilizing the recorded peaks in each of the 12 months of the selected test year.

Q. Why use peak demand as the basis for allocations?

A. Peak demand is the largest electric load requirement occurring on a utility's system within a specified period of time (e.g., day, month, season, year). Since generation units and transmission lines are planned, designed, and constructed to meet a utility's anticipated system peak demands plus required reserves, the contribution of each individual jurisdiction to these peak demands is the appropriate basis on which to allocate the costs of these facilities.

Q. Please describe the procedure for calculating the jurisdictional demand allocation factors using the 12 CP methodology.

A. The allocation factor for each jurisdiction was determined using the following process:

1. Empire's peak hourly load for each month in calendar year 2003 was identified and summed.

2. Each jurisdiction's loads corresponding to Empire's monthly peak hours identified in #1 above were summed.

3. Each of the results calculated in #2 above was divided by the sum of Empire's 12 monthly peak loads (result of #1 above).

This resulted in the allocation factor for each jurisdiction. The sum of the demand allocation factors across all jurisdictions equals one.

Q. How was the decision made to recommend using the 12 CP method?

A. The 12 CP method is appropriate for a utility, such as Empire, that experiences relatively small variations in monthly and/or seasonal (e.g., summer and winter) peaks during a particular year. Schedule 3, attached to this Direct Testimony, presents a table of Empire's maximum hourly peak in each month for calendar years 1997 through 2003. This information was taken from the Federal Energy Regulatory Commission (FERC) Form 1, and data provided by the Company in response to Staff Data Request No. 155 in this case, Staff Data Request No. 2921 in Case No. ER-2002-424, and Staff Data Request No. 2918 in Case No. ER-2001-299. As shown, Empire experiences its system peak during the summer months (July, August, and September); however, the monthly peaks occurring during the winter months (December and January) are relatively high due to the Company's high saturation of electric heat customers.

The line graph on Schedule 4 attached to this direct testimony represents a profile of each month's hourly peak as a percentage of its corresponding annual maximum hourly peak for calendar years 1997 through 2003 and for the monthly averages of these seven-years. It was derived from the data shown in Schedule 3. This indicates consistent peaks in both the summer and the winter across the time period.

Q. Is there additional support for the position that a 12 CP methodology is appropriate in this case?

A. Yes. In various cases, the FERC has, among other things, used a number of tests as a guide in its determination of an appropriate allocation methodology. These tests are arithmetical calculations whose results are compared to specific ranges that suggest which methodology may be more appropriate. Attached to my testimony as Schedule 5 is an excerpt (Chapter 5) from a publication entitled "A Guide to FERC Regulation and Ratemaking of Electric Utilities and Other Power Suppliers," Third Edition (1994), authored by Michael E. Small. As this excerpt shows, FERC has used these tests to support its adoption of a 12 CP methodology in a number of cases. On occasion, however, these tests have suggested that an alternative coincident peak methodology (such as a 4 CP) might be more appropriate.

Q. Please describe the tests you used in your selection of a CP methodology.

A. I utilized the following tests included in the aforementioned guidelines attached as Schedule 5:

Test 1 - Computes the difference between the following two percentages:

a) The average of the monthly system peaks during the reported peak period as a percentage of the annual peak, and

b) The average of the system peaks during the remainder of the test period as a percentage of the annual peak.

If the difference lies between 18% and 19%, the FERC has typically adopted a 12 CP methodology. If the difference lies between 26% and 31%, the FERC has typically adopted a 4 CP methodology.

Test 2 - The lowest monthly peak as a percentage of the annual peak.

If the resulting percentage is between 66% and 81%, the FERC has typically adopted a 12 CP methodology. If the resulting percentage is between 55% and 60%, the FERC has typically adopted a 4 CP methodology.

Test 3 - The average of the twelve monthly peaks in the reporting period as a percentage of the annual peak.

If the resulting percentage is between 81% and 88%, the FERC has typically adopted a 12 CP methodology. If the resulting percentage is between 78% and 81%, the FERC has typically adopted a 4 CP methodology.

Q. Did you apply these FERC tests to Empire's data?

A. Yes. As illustrated on Schedule 6, I calculated the following percentages using the demands recorded for the twelve-month period ending December 31, 2003:

Test 1 -	15.53%
Test 2 -	58.89%
Test 3 -	80.91%

Q. Please discuss the significance of these results.

A. The result of the first test (15.53%) falls well below the above-indicated 18%-19% range noted in FERC decisions that adopted a 12 CP methodology. Since a higher percentage suggests the use of a smaller number of coincident peaks, my calculated lower percentage only adds further support to my recommendation that a 12 CP methodology be adopted in the current case. The result of the second test (58.89%) falls within the 55%-60% range typically seen in cases that FERC has suggested using a 4 CP. The result of the third test (80.91%) narrowly falls outside the 81%-88% range noted in FERC decisions adopting a 12 CP methodology. Overall, the results of these tests, given the strength of Test 1, support a 12 CP methodology.

Q. Are there any other factors to consider in determining the appropriate allocation methodology?

A. Yes. These FERC tests are merely part of a larger set of factors historically utilized by the FERC in its determination of which coincident peak methodology should be used in electric utility cases. In a rate case decision involving Carolina Power and Light Company[1], for example, the FERC states: "…it is necessary to consider the full range of a company's operating realities including, in addition to system demand, scheduled maintenance, unscheduled outages, diversity, reserve requirements, and off-system sales commitments" (footnote omitted). In the adoption of the 12 CP methodology, FERC has cited these operating realities as important to its determination.

[1] *Carolina Power & Light Co.*, Opinion No. 19, 4 FERC ¶61,107 at 61,230 (Aug. 1978).

Q. How do these operational realities apply to Empire?

A. There are periods of time, typically in the spring or fall, when the usage level of the Company's native load customers is reduced. At such times, the Company is able either to perform necessary maintenance on its power plants or to pursue off-system sales, while retaining sufficient capacity to adequately meet its customers' requirements. Furthermore, the Company's capacity planning process takes into account all the hours of the year, not just the peak hour or any seasonal peak. These operational realities, along with the test results and aforementioned analysis, provide ample evidence to support Staff's recommendation to adopt a 12 CP methodology in the current proceeding.

Q. Did the Company incorporate the 12 CP methodology in its filing of this rate case?

A. Yes.

Q. Which Staff witness used your jurisdictional demand allocation factors?

A. I provided these jurisdictional demand allocation factors to Staff witness Doyle L. Gibbs.

ENERGY ALLOCATION FACTOR

Q. What energy allocation factors are you recommending be used in this case?

A. The factors are shown in Schedule 8 and repeated here.

Missouri Retail	0.8249
Non-Missouri Retail	0.1089
Wholesale	0.0662

Q. What types of costs were allocated on the basis of energy?

A. Variable expenses, such as fuel and certain operational and maintenance (O&M) costs, are allocated to the jurisdictions based on energy consumption.

Q. How did you calculate the energy allocation factor?

A. The energy allocation factor for an individual jurisdiction is the ratio of the normalized annual kilowatt-hour (kWh) usage in the particular jurisdiction to the total normalized Empire kWh usage. The sum of the energy allocation factors across jurisdictions equals one. The actual jurisdictional kWh usage totals were provided in the Company response to Staff Data Request No. 146.

Q. What adjustments were made to these recorded kWhs?

A. The Staff made the following adjustments to be consistent with the net system hourly loads used in determining normalized fuel costs:

a. Normalization Adjustment

b. Annualization Adjustment

c. Customer Growth Adjustment

d. Wholesale Weather Adjustment

Q. Did you calculate these adjustments?

A. No. Staff witness Janice Pyatte supplied adjustments a. through c. Please refer to Ms. Pyatte's testimony for a summary of these adjustments. Staff witness Richard J. Campbell provided me with the normal weather adjustment that I applied to the Wholesale jurisdiction. Please see Mr. Campbell's testimony for a description of how this adjustment was calculated.

Q. Which Staff witness used your jurisdictional energy allocation factors?

A. I provided these jurisdictional energy allocation factors to Staff witness Doyle L. Gibbs.

Q. Does this conclude your prepared Direct Testimony?

A. Yes, it does.

TESTIMONY FILED
BEFORE THE MISSOURI PUBLIC SERVICE COMMISSION

BY ALAN J. BAX

COMPANY	CASE NUMBER
Aquila Networks – MPS	ER-2004-0034
Union Electric Company d/b/a AmerenUE	EO-2004-0108
Empire District Electric Company	ER-2002-0424
Kansas City Power and Light	EA-2002-0135
Union Electric Company d/b/a AmerenUE	EO-2003-0271
Aquila Networks – MPS	EO-2004-0603
Union Electric Company d/b/a AmerenUE	EC-2002-0117
Union Electric Company d/b/a AmerenUE	EC-2002-1
Empire District Electric Company	ER-2001-299
Aquila Networks – MPS	EA-2003-0370
Union Electric Company d/b/a AmerenUE	EW-2004-0583
Missouri Public Service	ER-2001-672
Aquila Networks – MPS	EO-2003-0543
Union Electric Company d/b/a AmerenUE	EC-2004-0556
Union Electric Company d/b/a AmerenUE	EC-2004-0598

SYSTEM ENERGY LOSS FACTOR

Month	Net Generation	Net Interchange	Inadvertant Flows	Net System Input	Retail Sales	Wholesale Sales	Company Use	Losses
Jan-03	288,392,000	190,203,000	194,000	478,789,000	415,459,967	28,138,040	872,979	34,318,014
Feb-03	219,241,000	192,932,000	181,000	412,354,000	357,385,479	24,660,500	819,473	29,488,548
Mar-03	223,084,000	167,596,000	(245,000)	390,435,000	337,067,450	24,670,580	738,179	27,958,791
Apr-03	209,993,000	130,237,000	110,000	340,340,000	292,232,789	23,092,220	599,788	24,415,203
May-03	217,536,000	133,280,000	(241,000)	350,575,000	300,670,454	24,137,280	617,192	25,150,074
Jun-03	256,613,000	136,688,000	(175,000)	393,126,000	338,504,638	25,726,600	645,765	28,248,997
Jul-03	382,307,000	132,686,000	(69,000)	514,924,000	445,418,721	31,658,360	743,335	37,103,584
Aug-03	416,885,000	102,839,000	418,000	520,142,000	449,927,365	31,984,200	733,705	37,496,730
Sep-03	208,096,000	151,488,000	(90,000)	359,494,000	318,853,075	24,193,740	711,605	15,735,580
Oct-03	218,863,000	147,066,000	67,000	365,996,000	306,214,488	22,905,180	603,046	36,273,286
Nov-03	239,135,000	137,079,000	(176,000)	376,038,000	326,149,329	22,249,880	599,292	27,039,499
Dec-03	281,668,000	166,223,000	57,000	447,948,000	389,866,342	25,157,480	847,377	32,076,801
Totals	3,161,813,000	1,788,317,000	31,000	4,950,161,000	4,277,750,097	308,574,060	8,531,736	355,305,107

System Energy Loss Factor = Losses / Net System Input = 0.0718

Monthly System Peaks (MW)

	2003	2002	2001	2000	1999	1998	1997	Seven-Year Average
January	987	891	919	794	831	690	841	850.43
February	865	872	841	792	685	677	653	769.29
March	806	870	701	604	654	781	610	718.00
April	697	655	642	608	595	553	595	620.71
May	736	738	791	830	562	785	538	711.43
June	927	897	859.3	822	793	881	782	851.61
July	1019	984	999	946	958	910	876	956.00
August	1041	987	1001	993	979	916	839	965.14
September	813	950	878	961	850	888	786	875.14
October	613	804	618	743	586	536	623	646.14
November	754	748	769	754	621	600	673	702.71
December	849	820	764	941	770	809	700	807.57