R36-05 Final

Kansas City Power and Light Electric System Loss Analysis

Prepared for

Kansas City Power and Light

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Executive Summary

Kansas City Power and Light Company (KCPL) retained Siemens Power Technologies International (Siemens PTI) to analyze their electric power system and determine the electric system demand and energy losses for the test year 2004. This report describes how electric system non-coincident demand losses and energy losses were calculated and shows the results of the calculations. Coincident demand and energy loss multipliers were also determined using the results of the loss calculations.

KCPL operates its own control area within the States of Missouri and Kansas and is responsible for providing their customers with electric demand and energy requirements. In 2004 there were about 46 interconnection tie points to six neighboring control areas within the Southwestern Power Pool (SPP). Tie flow consists of scheduled flow, inadvertent flow or loop flow and can be in both directions. KCPL is responsible for the losses in the transmission system within their control area from these tie flows, as well as the flows from generating plants and purchases to the internal control area load.

The losses shown on page 401a of the FERC Form 1 are the starting point for a loss analysis study. The reported energy losses for year 2004 are 786,793 MWh. Demand and energy losses are used in the design of the company's electric rates. As part of this study effort, non-coincident demand losses were calculated for each of eight different subsystems in the electric system for the test year of 2004. These losses are considered to be technical losses. The eight subsystems are the following:

- Generator step-up transformers,
- Transmission lines,
- Transmission transformers,
- Distribution substation transformers,
- Distribution primary lines,
- Distribution secondary transformers,
- Distribution secondary lines and service drops, and
- Electric meters.

All transformers have a load loss component and a no-load loss component. Transmission lines above 69 kV have a corona losses component as well as the current-related component. In addition to these technical losses, there are two additional categories called energy diversion and substation light and power. Energy diversion is energy stolen by unscrupulous customers. Energy diversion is usually small in the USA but it must be considered as a loss and allocated to those customers who pay their way. These two categories are called non-technical losses.

KCPL connects its customers to the electric system depending on the customer demand requirements. Typically, large demand customers are connected directly to the transmission system and are normally considered industrial class customers or requirement sales customers. Intermediate demand customers are connected to the distribution primary system and are normally commercial and small industrial in nature. The smaller residential and commercial customers are connected to the distribution secondary system. The requirement sales customer class includes other utilities such as municipalities or REAs (Rural Electrification Administration).

Section 2 of the report describes the general methodology followed in the study. Sections 3, 4, 5 and 6 contain the detailed explanation of the method used to calculate the losses in the transmission, substation, distribution primary and distribution secondary systems, respectively.

Table E.1 in the Executive Summary shows the calculated electric system losses for year 2004. As shown in Table E.1, the total calculated energy losses were 762,104,743 kWh but the total Form 1 reported loss total was 786,793,000 kWh. The energy loss difference of 23,975,379 kWh was allocated to the following components, in proportion to their calculated total: secondary lines and service drops, secondary transformers (load loss), primary lines (4 kV, 12.8 kV, and 13.2 kV), primary transformers (load loss), transmission transformers (load loss), and transmission lines. Load losses are a function of the electrical current. The allocation was executed for these subsystems because the assumptions that were made regarding the customer load, diversity factors, load factors and loss factors, plus the sampling techniques used, may have a lower degree of confidence than the one for the no-load loss categories. The allocation process is described in Section 7. Table E.2 shows the non-coincident and coincident demands and energy losses as adjusted.

According to the 2004 FERC Form 1 report, page 401a, the sum of the energy sales to Ultimate Consumers, Requirements Sales for Resale, and Energy Used by the Company was 14,200,824 Megawatt Hours (MWh). Total energy losses were 786,793 MWh. The energy losses expressed as a percentage of the sum of the energy sales are 5.54 percent.

Table A1 and Table A2 in the Appendix show the loss multipliers for demand and energy, respectively. Loss multipliers are used to allocate losses to customers as a function of their voltage level of service. For example, if a residential customer required one kWh of energy, the generation system would have to provide 1.061288 kWh to cover the energy losses and the one kWh load. Similarly, if the same residential customer placed a demand requirement of one kW, the generation system would have to provide 1.080868 kW to cover the one kW load and the demand losses. Transmission customers are only responsible for their share of losses that result from their service on the transmission system. Substation customers are responsible for their share of losses on the substation system and the transmission system. Primary service customers are responsible for losses resulting from their load on the primary system, substation system and the transmission system. Secondary customers are responsible for losses that their load creates on all four systems.

Table E.1 Calculated Electric System Demand and Energy Losses for Year 2004

CALCULATED LOSSES			
	NON-COINCIDENT PEAK LOSSES KW	COINCIDENT PEAK LOSSES KW	ENERGY LOSSES KWH
TRANSMISSION SYSTEM			
Line	51,022	51,022	161,887,549
Transformer Load	2,489	2,489	5,543,466
Line Corona	153	153	2,896,493
Transformer No-Load	1,393	1,393	12,237,368
34.5 kV System	7,700	6,734	17,819,312
34.5 kV Transformer No-Load	442	442	3,878,795
Generator Step-Up No-Load	2,864	2,864	18,345,432
Sum	66,063	65,097	222,608,415
SUBSTATION SYSTEM			
Transmission to Distribution Load	26,465	23,145	61,244,424
Transmission to Distribution No-Load	7,317	7,317	64,275,803
Sum	33,782	30,462	125,520,227
PRIMARY DISTRIBUTION SYSTEM			
Distribution to Distribution Load	1,467	1,276	3,395,579
Distribution to Distribution No-Load	688	688	6,041,533
Primary Lines 4 kV	3,662	3,184	8,474,587
Primary Lines 15 kV Class	59,082	51,376	136,728,109
Sum	64,899	56,524	154,639,808
DISTRIBUTION SECONDARY SYSTEM			
Transformer Load	16,768	13,973	33,729,089
Transformer No-Load	12,786	12,786	112,308,370
Lines and Service Drops	51,571	42,976	103,639,107
Customer Meters	412	412	3,618,482
Sum	81,536	70,147	253,295,048
NON-TECHNICAL LOSSES			
Substation Station Light & Power	1,230	1,230	6,482,592
Energy Diversion	117	117	271,531
Sum	1,347	1,347	6,754,123
Total	247,627	223,577	762,817,621
TOTAL SYSTEM LOSSES CALCULATED	247,627	223,577	762,817,621
TOTAL REPORTED FERC FORM 1 LOSSES			786,793,000
LOSSES ADJUSTMENT NECESSARY			23,975,379

Table E.2 Adjusted Electric System Losses for Year 2004

ALLOCATED LOSSES			
	NON-COINCIDENT PEAK LOSSES KW	COINCIDENT PEAK LOSSES KW	ENERGY LOSSES KWH
TRANSMISSION SYSTEM			
Line	53,319	53,319	169,176,935
Transformer Load	2,601	2,601	5,793,074
Line Corona	153	153	2,896,493
Transformer No-Load	1,393	1,393	12,237,368
34.5 kV System	8,047	7,037	18,621,670
34.5 kV Transformer No-Load	442	442	3,878,795
Generator Step-Up No-Load	2,864	2,864	18,345,432
Sum	68,819	67,809	230,949,767
SUBSTATION SYSTEM			
Transmission to Distribution Load	27,657	24,187	64,002,105
Transmission to Distribution No-Load	7,317	7,317	64,275,803
Sum	34,974	31,504	128,277,908
PRIMARY DISTRIBUTION SYSTEM			
Distribution to Distribution Load	1,533	1,333	3,548,473
Distribution to Distribution No-Load	688	688	6,041,533
Primary Lines 4 kV	3,827	3,327	8,856,176
Primary Lines 15 kV Class	61,742	53,689	142,884,629
Sum	67,790	59,037	161,330,811
DISTRIBUTION SECONDARY SYSTEM			
Transformer Load	17,523	14,602	35,247,824
Transformer No-Load	12,786	12,786	112,308,370
Lines and Service Drops	53,893	44,911	108,305,713
Customer Meters	412	412	3,618,482
Sum	84,614	72,711	259,480,389
NON-TECHNICAL LOSSES			
Substation Station Light & Power	1,230	1,230	6,482,592
Energy Diversion	117	117	271,531
Sum	1,347	1,347	6,754,123
Total	257,544	232,408	786,792,998
TOTAL SYSTEM LOSSES ALLOCATED			786,793,000
	Allocated Losses		

Section

1

Introduction

The Kansas City Power & Light Company (KCPL) is a regulated investor-owned utility with their headquarters located in Kansas City, Missouri. KCPL serves about 500,000 customers in Kansas and Missouri and has a total generating capability of about 4,582 MW at nine major locations. Fuel sources for generation include coal, gas, oil, and nuclear. The peak demand in 2004 was 3,384 Megawatts (MW) and the annual energy requirement was 21,455,789 Megawatt hours (MWh) for sales to the ultimate consumer, including requirement sales, non-requirement sales, losses and company use. In the year 2004, KCPL's annual peak demand occurred in the summer.

The KCPL electric system has been growing at approximately the same rate as the national utility average over the past eleven years. Between the years 1994 and 2004, the average annual energy growth rate for the net system input was 1.9 percent and for demand it was 2.2 percent. Figure 1.1 shows the historical actual demand and the weather normalized demand for the years between 1994 and 2004.

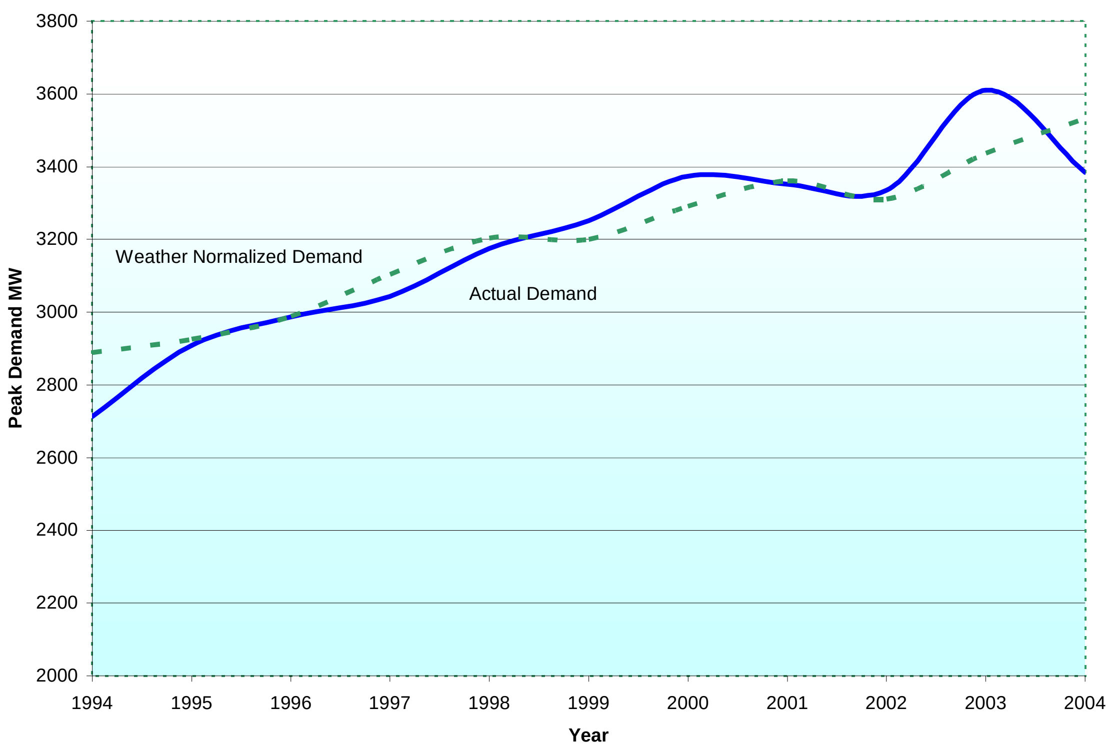

Figure 1.1. Peak Demand

KCPL operates its own control area and delivers energy across an interconnected transmission and distribution system. A control area is an electrical region within a larger bounded electrical area that adjusts generation within the area to control the interchange schedules with the neighboring areas. The KCPL control area is interconnected with six other control areas. There are about 46 different tie points across the control area to their neighbors. The high number of tie points increases the problem of loop flow or inadvertent flow and therefore has the potential to increase the losses on the transmission system. The control area operator is responsible for all losses that are a consequence of the operation in that control area within metered tie points, internal generation and load. There are two small KCPL substation loads outside their control area. KCPL transmission voltages are 345 kV, 161 kV, 69 kV, and 34.5 kV. The principal distribution voltages are 13.2 kV and 12.47 kV in Missouri, and 12.47 kV in Kansas. KCPL has a few 4 kV circuits.

The present report documents the determination of electric system losses on the KCPL system. Losses were not separated between Kansas and Missouri. Figure 1.2 below shows the recorded losses from 1994 to 2004. In general, during the years between 1994 and 2004, the losses, as a percent of the output, show a declining trend. Utility losses tend to remain somewhat constant over time. As the load grows the system is expanded by the addition of more transformers and lines. The KCPL losses should not continue to decline but should level out within the range shown.

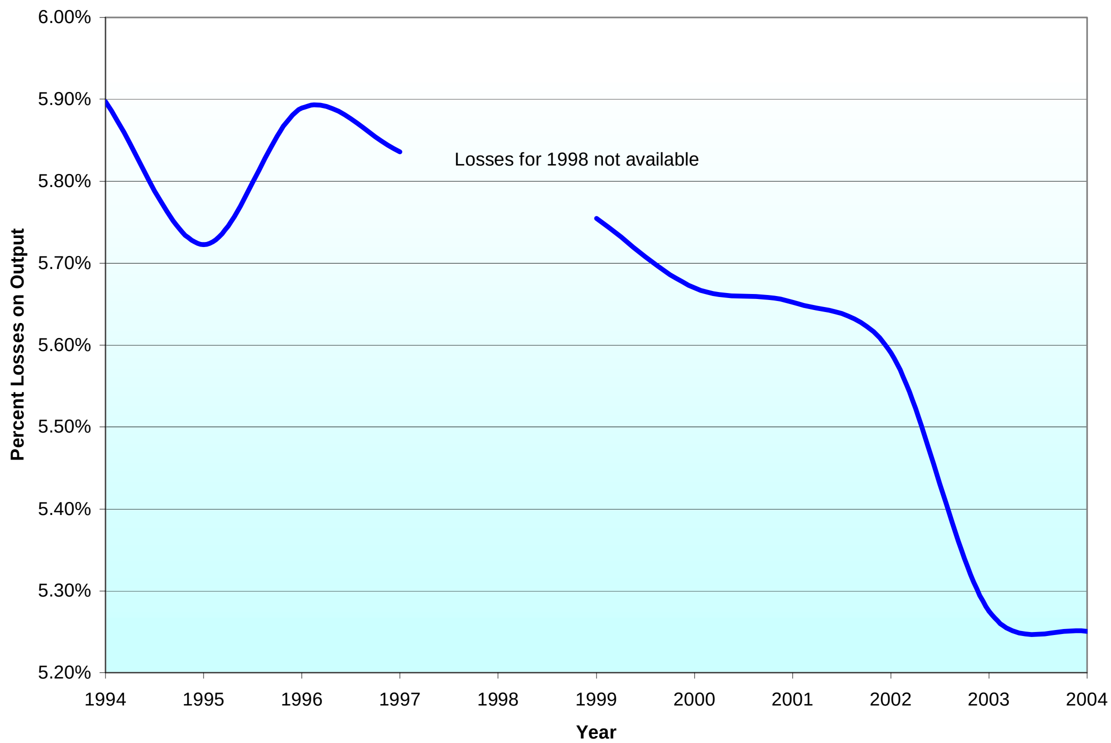

Figure 1.2. Electric System Losses

As part of this study effort, non-coincident demand losses were calculated for each of eight different subsystems in the electric system for the test year of 2004. These losses are considered to be technical losses. The eight subsystems are the following:

- Generator step-up transformers,
- Transmission lines,
- Transmission transformers,
- Distribution substation transformers,
- Distribution primary lines,
- Distribution secondary transformers,
- Distribution secondary lines and service drops, and
- Electric meters

In addition to the technical losses, there are two additional categories called energy diversion and substation light and power. Energy diversion is energy stolen by unscrupulous customers. Energy diversion is usually small in the USA but it must be considered as a loss and allocated to those customers who pay their way. These two categories are called non-technical losses.

Section

2

Methodology

The Edison Electric Institute (EEI) defines losses as the general term applied to energy (kilowatt hours) and power (kilowatt) lost in the operation of an electric system. Losses occur as energy is transformed into waste heat in electrical conductors and apparatus.

Demand loss is power loss and is the normal quantity that is conveniently calculated because of the availability of simplified equations and data availability. Demand loss is coincident when occurring at the time of the system peak and non-coincident when occurring at the time of equipment or subsystem peak. Class peak demand occurs at the time when that class's total peak is reached.

Total energy loss can be determined for an electric system because of system metering. Energy losses are calculated by taking the difference between all the known metered inputs to the electrical system and subtracting all the known outputs. Inputs and outputs at the control area boundaries and generator outputs are normally recorded in increments of MW per hour. These values, therefore, encompass the total system energy input on a year-end to year-end basis. Readings from most customer meters are recorded each month by meter reading methods that can only record about a twentieth of the meters each business day in the month. Thus, while each customer has an annual energy recorded, it is not based on a true calendar year consumption period. This results in a meter reading billing cycle error. When the December and January weather patterns are similar from one year to the next, the billing cycle error is minimized. When taken over several years, the cumulative error average tends to zero out. KCPL reads many of their customer meters by electronic means and this error is minimized.

It is cost effective to use meters for large load-customers that can measure energy on a periodic basis such as an hour or every 15 minutes. But for residential customer loads, it is not as practical due to the cost of the more expensive meters.

There is another potential difficulty in that every load must be metered and recorded. A large error is introduced when one load is not metered or when there is an error in recording the energy. Capturing all loads becomes very important. In addition to measuring the loads, it is important that a utility's accounting system include all loads and that the mathematical sign (addition or subtraction) be proper. Moreover, there are loads that have no meters so that the energy use has to be estimated. Loads like street lighting may be conveniently estimated because the hours of operation and size of the fixtures can be used to determine the energy use. Substation station power and light requirements are also not normally metered. All these factors have been identified as part of many other utilities' loss accounting problems.

Large utilities are required by FERC to provide the annual energy loss value by taking the difference between the inputs to the system and the outputs and presenting this loss value on page 401 of the Form 1. The KCPL data for the year 2004 FERC Form 1 is shown in Table 2.1. Non-requirement sales are energy sales to other utilities service areas. These purchases by others sometimes include a provision for loss compensation. When calculating losses these off-system sales are not included. For the year 2004, the loss percent is 5.54%, calculated as the total of the customer sales, requirement sales and company-use divided into total losses.

Table 2.1 2004 FERC Form 1 - Energy Account

SOURCES OF ENERGY	MWh	DISPOSITION OF ENERGY	MWh
Generation (Excluding Station Use)		Sales to Ultimate Consumers (Including Interdepartmental Sales)	14,044,103
Steam	15,844,601	Requirement Sales for Resale	134,350
Nuclear	4,762,379	Non-Requirement Sales for Resale (Off-system sales)	6,468,171
Hydro Conventional	-	Energy Furnished without Charge	-
Hydro-Pumped Storage	-	Energy Used by the Company	22,371
Other	-2,129	Total Energy Losses	786,793
Less Energy for Pumping	-	Total	21,455,788
Net Generation	20,604,851		
Purchases	850,937		
Power Exchanges:			
Received	-		
Delivered	-		
Net Exchanges	-		
Transmission for Other (Wheeling)			
Received	512,031		
Delivered	512,031		
Net Transmission for Other	-		
Transmission by Others Losses	-		
Total	21,455,788		

The total system energy losses of 786,793 MWh shown in the table above are calculated by taking the metering difference between the total inputs and total outputs. This method cannot be used in each of the subsystems in the electrical network because the meters are not located at the input to each subsystem. Therefore, this total system energy loss value becomes our target value for the total energy losses in allocating losses to each subsystem.

There are eight categories or subsystems that can be established to define and calculate specific losses that occur on the electric system. Within these categories there may be load and no-load losses. In short, load losses depend on the load, and no-load losses are independent of the load. These categories and the presence of load and/or no-load losses are provided in Table 2.2.

Table 2.2 – Categories of Load and No-Load Losses

Category	Load Losses	No-Load Losses
Transmission Lines	Yes	No
Corona	No	Yes
Transmission Transformers	Yes	Yes
Distribution Substation Transformers	Yes	Yes
Primary Distribution Lines	Yes	No
Distribution Secondary Transformers	Yes	Yes
Service Drops	Yes	No
Meters	No	Yes

The demand and energy losses for the KCPL system have been calculated for these eight categories and have been allocated to the rate design voltage levels. The four voltage level classifications used in the allocation match the rate class service levels, transmission service (with voltages of 345 kV, 161 kV, 69 kV, and 34.5 kV), substation service, distribution primary service (13.2 kV, 12.47 kV and 4 kV), and secondary service (with supply voltages of 480 V, 277 V, 208 V, 240 V, and 120 V). The voltage level of service is a function of the demand. The method used to calculate losses in each of these eight categories and the procedure used to allocate losses to the four voltage levels of service are discussed in the following sections. In summary, the non-coincident demand losses are calculated for each subsystem, and then the coincident demand and energy losses are calculated from the non-coincident values.

The loss factor methodology was used to determine energy losses from the non-coincident peak (NCP) loss for each subsystem's load losses except for the transmission system which has a looped configuration. The loss factor methodology works well only in radial systems. Non-coincident demand losses for transformer load losses or secondary line losses were calculated using standard engineering equations and practices. The calculated non-coincident demand loss was used with calculated loss factors and 8,784 hours for the year 2004 to determine annual energy losses. Diversity factors were used if the subsystem (component, customer class or voltage level loads) demand was known to get back to the non-coincident value. Loss factors can be calculated for each service level voltage using the 8,784-hour load research data for the test year of 2004. Load and loss factors were calculated using equations 1 and 2, respectively, and the hourly load research data by service level or customer class. This is the exact method to determine these two factors.

Equation 1 - Load Factor:

$$F_1 = (1/8760) \sum_{i=1}^{8760} l_i$$

where: F_1 = load factor
l_i = hourly load (per unit)

Equation 2 - Loss Factor:

$$F_l^2 = (1/8760) \sum_{i=1}^{8760} l_i^2$$

where: F_l^2 = loss factor

Equations 1 and 2 are written for an 8760-hour year. Equation 1 defines the load factor as a function of each hour's load in per unit value for a year, but any time increment can be used (such as 15 minutes with adjustments of 4 times the 8760 constant in the equation). The test year 2004 was a leap year so 8784 hours were used. This equation can be used to calculate the load factor at any voltage service level, customer class, or combination of customer classes if the time series data is available.

Equation 1 is structured for a period defined as a year and is consistent with EEI's definition of load factor as follows:

> The ratio of the average load in kilowatts supplied during a designated period to the peak or maximum load in kilowatts occurring in that period.

Equation 2 is the loss factor. The loss factor has the following definition:

> The ratio of the average loss in kilowatts occurring during a designated period to the peak or maximum loss occurring in that period.

Each of these equations can be modified for a leap year and for load research data that have increments of less than one hour. Equations 1 and 2 are well suited for computerization and were used to calculate the load and loss factors for each service level and for the total system load.

Equation 3 shown below can be used to calculate the loss factor when time series data is not available. Generally, this equation gives very good results for USA utilities and it worked very well when it was applied to the KCPL system. This equation gives significantly more accurate results than older equations that calculate the loss factor as a function of coefficients that have little or no relationship to the load shape. The calculated loss factor can then be used to calculate energy losses from the demand loss.

Equation 3: $L_{loss} = (L_{load})^{1.912}$

Where, L_{loss} and (L_{load}) are the loss and load factors, respectively.

Using Equations 1 and 2, load and loss factors were calculated from load research data and the control area subsystem data provided by KCPL in EEI format. The control area subsystem is the transmission voltage level service rate class. Load research data was not available for the substation voltage level class of service. The calculated load and loss factors are shown in Table 2.3. The load factors are based on the non-coincident peak of the corresponding subsystem.

Table 2.3. Load and Loss Factors

SUBSYSTEM LOAD AND LOSS FACTORS		
Subsystem for 2004	**Load Factor**	**Loss Factor**
Secondary	0.462	0.229
Primary	0.499	0.263
Control Area (EEI)	0.503	0.265

Section

3

Transmission Service Level

The KCPL transmission system is comprised of lines with voltages of 345 kV, 161 kV, 69 kV and 34.5 kV, and transformers with high and low side voltages with these same voltages. The methodology used to calculate the losses in the transmission lines and transformers depends on their voltage level. The methodology used for voltages 69 kV and above is described in the following sub-section. Due to the fact that the 34.5-kV system is a radial one, the corresponding losses were calculated separately using the load factor/loss factor method described in Section 2. The losses in the generation step-up transformers were included as part of the transmission system losses. The total transmission losses were broken down into transmission line losses and transformer losses.

The operation of transmission lines results in a resistive loss which is a function of the current squared (load loss), and corona losses which is a function of the voltage squared (no-load loss). Similarly, transmission transformer losses have a resistive component which is a function of the current squared (load loss), and an excitation component which is a function of the voltage squared (no-load loss). Corona losses and excitation losses produce a reasonably constant loss because voltage remains relatively constant. There is a demand component and an energy component for all load losses and no-load losses.

PSS/E revision 29 software was used to calculate the KCPL transmission losses for 2004.

3.1 Transmission System Load Losses for Voltages 69 kV and Above

KCPL operates its own control area. The resistive losses (current squared times resistance) for the transmission lines and transformers within the KCPL control area are a function of the control area load, internal generation, purchases, power sales, wheeling, and inadvertent power flows through the control area. In looped systems, the flows related to these sources and loads do not follow a set pattern. For example, at one point in time and at specific locations, the direction of the flows in certain part of the system may be from north to south and at other times from south to north. Null points during the transition periods (times when flow is zero or near zero within the control area on any specific line) result in zero or near zero losses. The unpredictability of these flows and the duration of null points complicate the calculation of losses on the transmission system and all but eliminate the ability to use a load factor/loss factor methodology.

KCPL provided five 2004 power flow cases for this loss study (summer peak, winter peak, fall peak, April minimum and summer shoulder). The cases represent different system conditions for the SPP (Southwestern Power Pool) electric system, which includes the KCPL control area and other SPP and non-SPP control areas. The resistance of the transformers was added to the power flows so that both the line losses and transformer losses could be determined during the power flow simulation. Using the five power flow cases and by varying the generation, load, and interchange flows, a total of 24 cases were developed for the loss calculation. The change in loads, internal generation, and tie flows, represent system load levels from minimum load to maximum load.

The losses in the KCPL transmission system for voltages 69 kV and above were calculated by solving the series of 24 power flows. The losses were plotted against the total KCPL system loads as shown in Figure 3.1. A regression analysis was performed and a logarithmic curve was fitted to the 24 sets of data using standard curve fitting methods. The calculated losses determined using the regression function is also shown in Figure 3.1 along with the losses calculated using the 24 power flow cases.

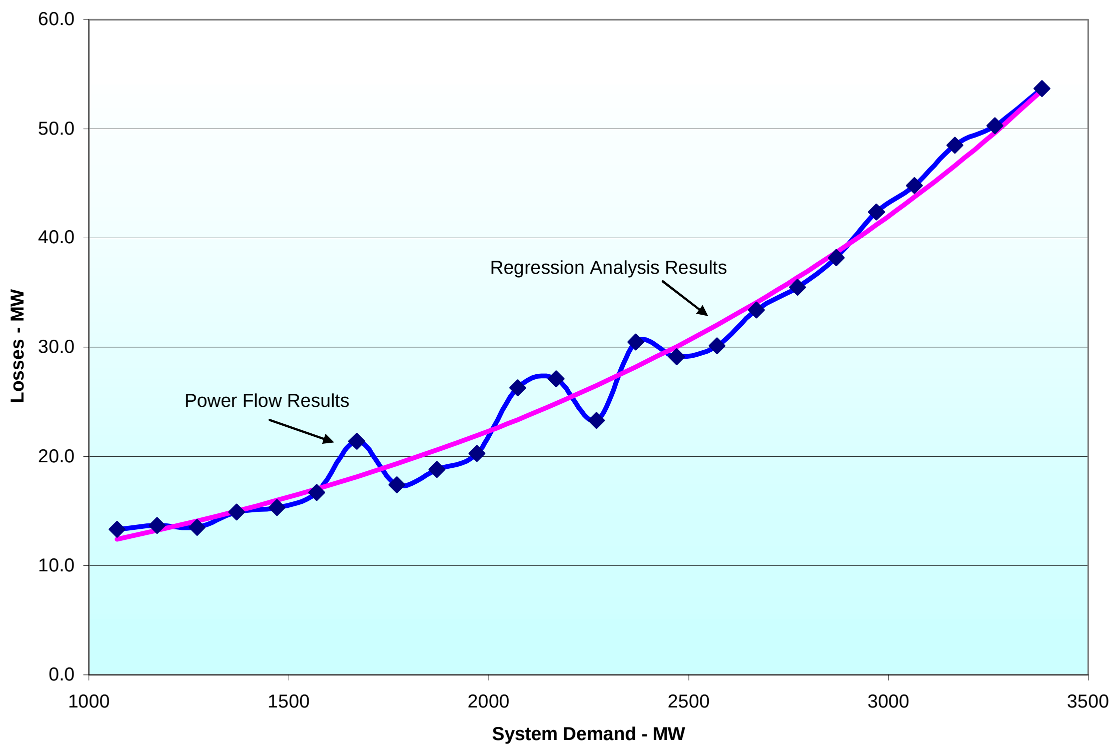

Figure 3.1. Transmission System Losses for Voltages 69 kV and Above

The results from the solution of the 24 power flow cases that were studied show that a relationship exists between the calculated loss and the control area load. The summer peak is the system maximum and has the highest percentage of transmission losses, at 1.6 percent, based on total system load. Minimum losses are about 1.0 percent and occur at low load levels but not at minimum load. The percentage loss at minimum load is about 1.2 percent. Besides the load level, transmission losses are very much dependent of the generation dispatch and inter-tie flow patterns. It was observed that relatively high inter-tie flow levels result in relatively low losses and relatively low inter-tie flow levels result in relatively high losses. This behavior is reflected in Figure 3.1 above, where power flow results which are higher than the values calculated using the regression curve results are associated with low inter-tie flows and vice-versa.

In order to find the total transmission losses for transmission lines and voltages 69 kV and above, the regression function was used. However, it is not possible to integrate this function directly between the minimum and maximum load because there may be multiple load data points with the same value between the minimum and maximum load. Therefore, a load duration curve, shown in Figure 3.2, was developed for the KCPL transmission system to perform the integration. The load duration curve shows the relatively smooth transition of increasing loadings from the knee of the curve to the peak load.

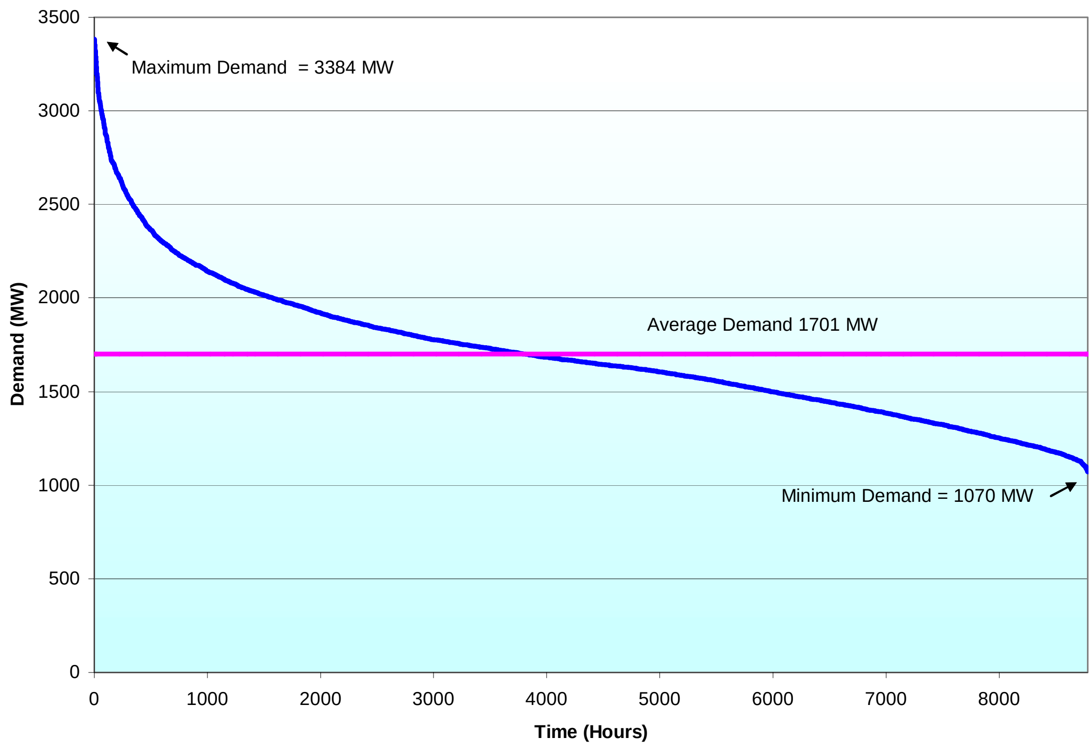

Figure 3.2. KCPL System Load Duration Curve

The regression analysis produced an equation or function that was based on total system load. The KCPL control area 8,784-hourly loads for the year 2004, provided by the SCADA system, represent the loads plus losses within the control area. The regression function was used to calculate the corresponding losses for the 8,784 hourly data. The sum of the losses for each hour of the entire year is 167,421,015 kWh. The control area peak demand was 3,384 MW (including losses) and occurred on July 13, 2004 at 17:00 hours. The total transmission loss at this peak was calculated as 53.7 MW or 1.59 percent of the total system load.

Figure 3.3 shows the control area load and losses on the peak day. As it would be expected, the losses are greater at the peak time than at the minimum load time. The area between the two curves represents the energy losses for the day.

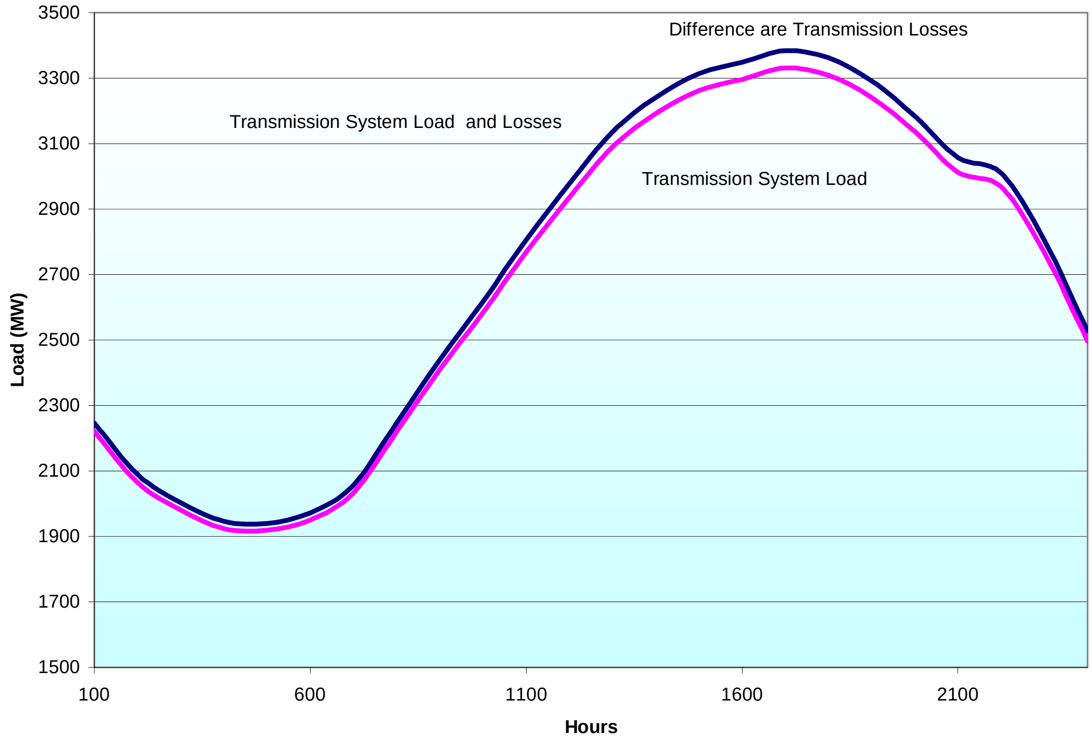

Figure 3.3 Transmission System Peak Day Load and Losses

3.2 Transmission Transformers No-Load Losses

The calculation of the no-load losses of transformers with voltages 69 kV and above is described in this section.

Transformers have two distinctive characteristics that result in losses. The first one is called iron loss or excitation loss and is caused by the excitation current or magnetizing current of the transformer core. This loss is always present as long as the transformer is energized and is a function of the voltage squared. Sometimes the iron or excitation loss is called no-load loss because it is nearly constant over the year and does not significantly vary as a function of the load. These losses are in the form of heat energy and noise. In this report, the term no-load loss is used to describe the iron or excitation loss.

The no-load losses are calculated by taking the capacity of each transformer and multiplying it by the per unit no-load loss. The per-unit no-load loss is usually provided by the transformer manufacturer. When data is not available, typical per unit no-load loss data is used. Transmission transformers where typical data was used for the no-load loss calculation are indicated on Table A3 in Appendix A. The same table shows the results of this analysis, providing the demand losses portion of the no-load loss. The energy loss is calculated by multiplying the demand loss by the number of hours in the period, which in this case is 8,784. The no-load coincident and non-coincident demand losses for the transmission transformers are both 1,393 kW and the corresponding annual no-load energy loss is 12,237,368 kWh. The coincident and non-coincident no-load losses for transformers are the same because of the constant nature of the loss.

The no-load losses in the step-up transformers of generators were calculated separately and the results are shown in Table A5 in the Appendix A. The no-load coincident and non-coincident demand losses are both 2,864 kW and the corresponding annual 2004 no-load energy loss is 18,345,432 kWh. In the calculation of the no-load demand losses for the generation step-up transformers the actual number of operating hours of the corresponding generators for year 2004 was used.

The second characteristic is the load losses. The resistance of the transmission transformers and generator step-up transformers was inserted into the power flow transformer data. Therefore, the load losses were determined as part of the power flow calculating process and are already included in the results as explained in the sub-section 3.1 above.

3.3 Corona Losses in Transmission Lines

Corona loss is an electric discharge to the air surrounding an energized conductor. The amount of discharge is principally a function of the voltage level and diameter of the conductor during fair weather conditions. Other factors influencing corona discharge are adverse weather conditions, elevation, conductor spacing, and presence of a shield wire. Rain increases the corona loss substantially.

Corona demand losses were calculated separately for the 345-kV, 161-kV, and 69-kV transmission lines, using the Bonneville Power Administration computer program, CORONAII, Corona and Field Effects. Corona loss is negligible for voltages of 69-kV and below in fair weather conditions. Table A8 in the Appendix lists the miles of KCPL transmission lines by voltage and the calculated corona losses.

The corona losses are based on normal conditions for most of the hours in a year. According to publicly available sources, there was an average of 0.33 inches of rain for about 115 hours in the geographical area where the KCPL transmission lines are located. The total demand loss due to corona effects was calculated assuming normal conditions. The coincident and non-coincident demand loss is 153 kW and the energy loss is 2,896,493 kWh.

3.4 34.5 kV System Transmission Load Losses

The 34.5 kV KCPL system is a radial system. The non-coincident peak load losses of the 34.5 kV system were calculated using the load factor/loss factor methodology described in Section 2. The calculated losses include the load losses in all 34.5 kV lines and the 161/34.5 transformers.

KCPL provided two summer peak power flow cases, one case with the 34.5 kV system modeled and another case without it. The 34.5 kV system loads modeled in the summer power flow case were compared to the substation loads provided by KCPL separately and were not modified as the loads were found to be very much in agreement.

The non-coincident peak 34.5 kV system load loss was found as the demand loss difference in the two summer peak power flow cases for the KCPL control area. The non-coincident peak is 7,700 kW. Using load research data provided by KCPL, a loss factor of 0.263456 was calculated for the 34.5 kV system and the resulting energy losses were 17,819,312 kWH.

Using revenue class information provided by KCPL, the non-coincident peak/coincident peak ratio was calculated for primary consumers. This ratio is 1.1434. Therefore, the coincident peak losses are 6,734 kW.

3.5 161/34.5 kV Transformers No-Load Losses

The calculation of the no-load losses for the 161/34.5 kV transformers was performed using the same methodology employed for the calculation of the no-load losses of the transformers for system voltages 69 kV and above described in sub-section 3.2 above. The no-load losses are presented in Table A4 in the Appendix.

The non-coincident and coincident peak no-load losses are 442 kW and the energy no-load losses are 3,878,795 kWH.

3.6 Transmission System Calculated Losses

The transmission system calculated losses were divided into transmission line losses and transformer losses. The losses were further divided into no-load losses and load losses and are summarized in Table 3.1. The transformer losses include the losses in all KCPL transformers 34.5 kV and above, including the step-up transformers in power plants. The transmission line losses include the losses in all lines 34.5 kV and above.

Table 3.1 Transmission System Losses Summary

	Transmission Lines		Transformers		Totals	
	Load Losses	Corona Losses	Load Losses	No-Load Losses	Load Losses	No-Load Losses
Non-Coincident Peak (kW)	58,722	153	2,489	4,699	61,211	4,852[1]
Coincident Peak (kW)	57,756	153	2,489	4,699	60,245	4,852
Energy Losses (kWh)	179,706,861	2,896,493	5,543,466	34,461,595	185,250,327	37,358,088

[1]Includes the Corona losses

Section

4

Substation Service Level

The substation service level is one of the four voltage service levels that customers can apply for service. This service level is made up of the transmission to distribution voltage transformers called primary distribution transformers. Primary distribution substation transformers are those transformers with a high side transmission voltage of 345 kV through 34.5 kV and a nominal low side voltage in the distribution primary voltage range. There is a subset of this category that has the high side voltage in the distribution range and the low side also in the distribution range, 12.47 kV to 4 kV for example but these will be discussed in the next section.

KCPL has a metering and recording system that provides the peak loads for their primary distribution transformers. These peak loads were used to calculate the load losses using the transformer manufacturer's resistance in per unit value where available. Typical values were used for those units without manufacturer's data; transformers where losses were calculated using typical values are indicated in the Appendix. The per unit values used to calculate the load and no-load losses are based on the transformer's OA (oil to air) rating. This rating is shown as the Base Rating. The Bank Rating is a higher rating FA (fan to air) or FOA (fan to air and pumped oil) because of enhanced cooling. The higher of these later two ratings is what determines the transformer loading capability. In some cases only the Bank Rating was available. In these cases, the Base Rating was estimated based on standard relationships for the OA-FA-FOA transformer rating system. The transformers where loading data was unavailable are indicated in Table A6 and were assigned an average utilization based on the OA rating or base rating.

The load factor/loss factor methodology was used to calculate energy loss from demand loss for the load loss portion of transformer losses. The load factor/loss factor methodology is discussed in Section 2 of the report. Table A6 in the Appendix shows the load and no-load losses, both demand and energy, for each individual transformer. The total non-coincident demand losses are 26,465 kW and 7,317 kW for the load and no-load components, respectively. The total coincident demand losses are 23,145 kW and were calculated from revenue class information provided by KCPL. The energy losses are 61,244,424 kWh and 64,275,803 kWh, for the load and no-load components, respectively.

Section

5

Distribution Primary Service Level

The primary distribution service level is considered to have circuits operating at voltages of 4 kV, 12.47 kV, and 13.2 kV. There are a few circuits in the distribution voltage range that act like a sub-transmission system; that is, they have a lower distribution voltage transformer and circuit connected. An example would be a 13.2-kV circuit that provides the energy to a 4-kV circuit.

The losses on the distribution primary system have been calculated separately for three categories, each with demand and energy components: distribution substation transformer load losses, distribution substation transformer no-load losses, and primary line or circuit losses. The present section discusses the methodology used to calculate the losses in the primary lines. The following section describes the methods used to calculate the primary distribution transformer losses, both load and no-load.

5.1 Primary Distribution Lines

KCPL has three main primary distribution voltages, 4-kV, 12.47-kV, and 13.2-kV. The 4-kV circuits are older circuits and are not expanded if higher voltage lines can take on the load. There are 37 of these circuits in the system. There are about 600 primary circuits. KCPL maintains a database of their circuits and the individual peak loadings, non-coincident with the system peak.

Primary distribution circuit losses were calculated using the Siemens PTI distribution computer model, PSS / ADEPT. The computer model is capable of representing three phase, two phase, and single line to ground distribution lines. It is necessary to model the conductor type, conductor length, and connected loads by phase. The program has the capability to model the distribution secondary transformer but this step was accomplished separately. The transformer node, however, was utilized as the connected load node. The ADEPT model calculates the flows and voltages at each of the nodes. The conductor resistance and the neutral return and ground resistance have been factored into the loss calculation. Most of the circuit information was available in electronic format from the KCPL distribution computer program but the data input/output were in a different format.

A sample of ten distribution circuits was selected with different loads, lengths, and customer types. Overhead and underground circuits were also part of the sample. Non-coincident peak losses were calculated. A standard regression analysis was performed to find to find an exponential equation that would fit the results. The exponential equation is shown in Figure 5.1.

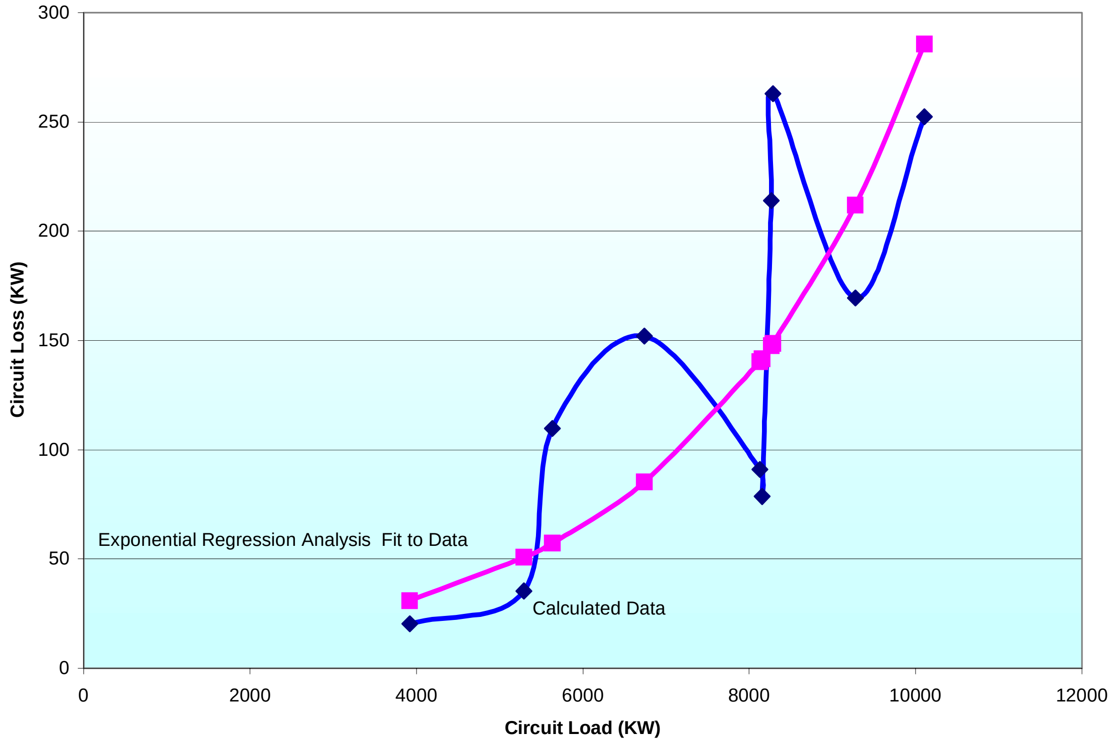

Figure 5.1. Calculated Distribution Circuit Losses

In Figure 5.1 the curve marked "Exponential Regression Analysis Fit to Data" is the curve that was developed to represent all KCPL circuits. The data peak losses calculated for these ten circuits are also plotted.

Figure 5.2 shows the frequency distribution of the kVA load for the combined 12.47-kV and 13.2-kV circuits. The losses of each of these circuits in the frequency distribution were calculated using the exponential equation. The non-coincident demand loss was used with a loss factor of 0.263 to determine the annual energy losses for each circuit. The reciprocal of the coincident factor of 1.15 (diversity factor) was used to determine the coincident peak, this is, the peak at time of the system peak.

5.2 Distribution to Distribution Transformer

There are a small number of distribution voltages to distribution voltage transformers. The losses on these transformers are shown in Table A7 in the Appendix. The same procedure was followed to calculate these losses as described for the distribution primary transformers.

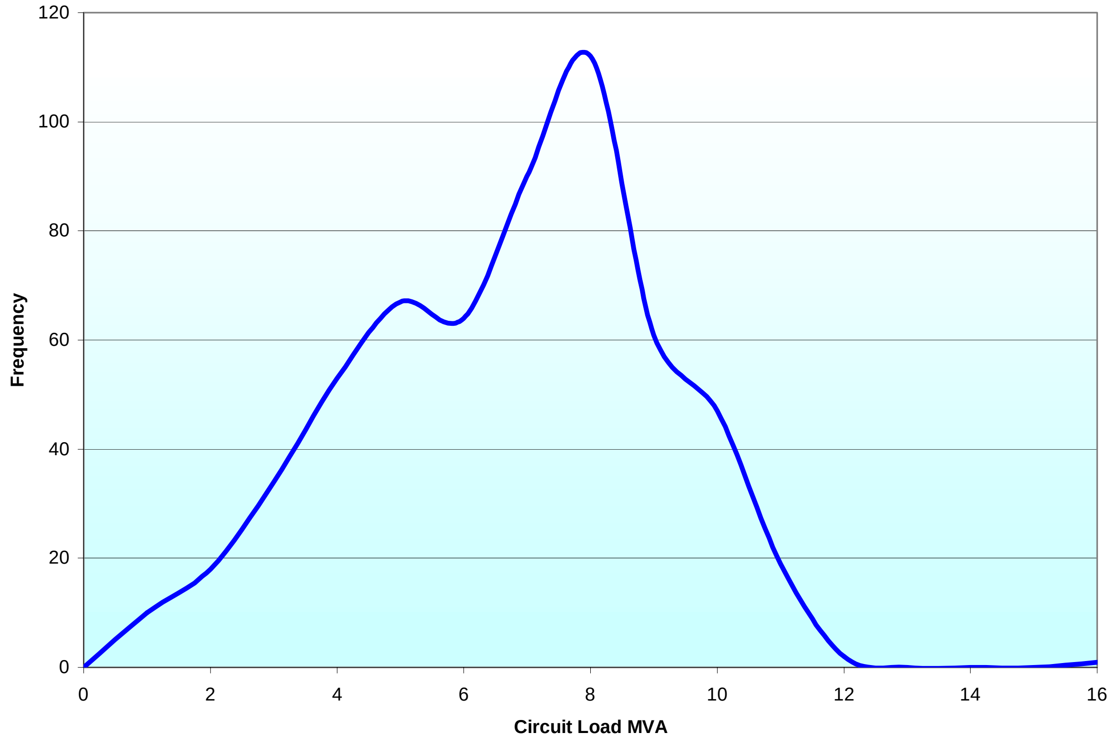

Figure 5.2. 12.47-kV and 13.2-kV Circuit Loading Frequency Distribution

There was no load data available for the 37 4-kV circuits. Based on the average loss for the higher voltage distribution circuit it was assumed that the 4-kV losses would have the same loss but would carry less load. The same loss factor and coincident factor were used for the 4 kV circuits.

Section

6

Distribution Secondary Service Level

The secondary distribution service level is comprised of secondary distribution transformers, secondary distribution lines, distribution service drops, and customer meters. While they all deal with low-voltage facilities, each of these requires specific analysis to develop their contribution to overall losses. This section will discuss the methods used to calculate the load and no-load losses on these secondary distribution components.

6.1 Secondary Transformers

The inventory of secondary transformers on the KCPL system ranges in size from 1 kVA to 3,000 kVA. In the 2004 test year there were about 93,405 transformers representing a total capacity of 6,292,904 kVA. The average transformer non-coincident load or utilization used in the calculation of losses was approximately 54 percent of the total transformer capacity. This utilization was established using the load research non-coincident demands for the secondary customers and a diversity factor of 1.2.

The load and no-load impedances were determined from historical data of selected transformer sizes provided by KCPL. The non-coincident load demand loss was determined by squaring the utilization, multiplying it by the load loss impedance, and multiplying that product by a factor of 1.09. This latter factor takes into account the square function of the average utilization, assuming a simple distribution around the average value. The result of this calculation is for one typical unit at each capacity rating. In order to get the total demand loss, it is necessary to multiply these values by the number of units in each capacity rating. Energy loss is determined by using the load factor/loss factor method and hours in a year. The secondary system non-coincident load factor was assumed to be 0.462 and the loss factor was calculated to be 0.229.

The no-load demand losses were calculated by multiplying the no-load impedance times each transformer size and by the number of units. Energy loss was determined from the demand no-load value by multiplying it by the hours in a year.

6.2 Secondary Lines and Service Drops

Losses that occur on secondary runners and service drops are the most difficult to calculate because of the lack of data. Information as to the configuration, conductor size, and length of each of the secondary services to customers are not kept on a drawing because a large number of drawings would be required. For the secondary services, KCPL has distribution standards that describe the standard conductor configurations to be used to serve the customers connected to the secondary distribution transformers. While each customer's electric service installation is slightly different than the standard, these distribution standards can serve as a guide for most facilities. Twelve typical circuits were used to calculate the demand losses, ten residential and two commercial.

The customer load was assumed to be un-balanced for the 240/120 volt configurations, with 55 percent of the load current on one leg, 45 percent on the other leg, and the 10 percent unbalanced load on the neutral. The hourly load research data for each customer class was summed up to create a secondary system load and primary system load data set. This data was for a full year but was created by a new system that started in July of 2004 so coincident and no-coincident peaks were not available for the test year. These coincident and non-coincident peaks were estimated based on assumed coincident factors. The secondary system has a non-coincident demand of about 2,835,643 kW. There are approximately 459,622 secondary customers that make up this system load. Based on the non-coincident peak load, the average customer load is 8.1 kW or 10.8 kVA when a power factor of 0.75 is assumed.

The calculated losses were calculated resulting in a demand loss of 51,571 kW, while the energy loss was 103,639,107 kWh. The same load factors and loss factors that were used for the secondary transformers were used for the secondary lines and service drops.

6.3 Customer Meters

A small quantity of losses can be attributed to each customer meter on the electric system. The standard mechanical residential meter takes about 0.9 watts of energy for each hour of operation. All meter losses are excitation losses. The electronic meters are more efficient because they have no moving parts. Their energy loss is about 0.25 watts per hour. Three phase meters have slightly higher losses for the mechanical and electronic types.

The demand loss for electric meters was calculated by multiplying the number of meters by the hourly losses of each meter type. The energy loss is determined by multiplying by the number hours in the year.

Table 6-1 shows the number of in-service losses and the demand and energy losses.

Table 6-1 Meter Losses

Meter Type	Quantity	Loss/Meter Watts	Demand Loss Watts	Energy Loss kWh
Single-Phase Mechanical	488,597	0.80	390,878	3,433,469
Three-Phase Mechanical	14,215	1.00	14,215	124,865
Three-Phase Electronic	27,390	0.25	6,848	60,148
Sum	530,202		411,940	3,618,482

Section

7

Methodology for Allocation of Energy Losses

There are many variables and assumptions that are necessary to make in the calculation of non-coincident demand losses for the eight categories described in Section 1. After the non-coincident demand losses were calculated there were additional assumptions that were necessary to make in order to calculate the energy losses. Those losses that are a function of the electric current have the most variables and assumptions in the process. The complexity of the task could be demonstrated if every load at every customer location on every transmission, distribution line, secondary line, and transformer were calculated for each hour in a year. Data necessary would be the time series load, voltage and power factor for each customer and the customer location on the lines and transformers being studied.

Loads are estimated for a peak condition at each location and loss factors applied as indicated in Section 2. Sample lines are selected to represent the total. The losses calculated are representative but they depend on the assumptions made.

In the case of no-load losses there are fewer assumptions required and the losses are relatively constant so going from demand to energy is a straight forward process. A record of the inventory and losses for each unit is normally maintained. There is a higher degree of confidence in these calculations than in the calculation of those that are based on loss factors and sampling.

The target losses of the sum of these eight categories are the FERC Form 1 reported losses. These losses are the sum of all energy that goes into the system and all the energy that leaves the system. As indicated in Section 1 there are reasons that explain why the reported losses may not represent the annual losses exactly but this is the best number available. The difference from the sum of the calculated losses for the eight categories and the target losses must be allocated to match the target value.

This allocation was made on those categories that are a function of current. These categories are: secondary lines and service drops, secondary transformers (load loss), primary lines (4 kV, 12.8 kV, and 13.2 kV), primary transformers (load loss), transmission transformers (load loss), and transmission lines. An energy loss difference of 23,975,379 kWh was allocated among these categories, in proportion to their calculated totals.

Appendix A

TABLE A1-COINCIDENT DEMAND LOSS MULTIPLIERS

	Total System		Secondary Service		Primary Service		Substation Service		Transmission Service	
SERVICE LEVEL	**kW**	**Multiplier**	**kW**	**Cumulative Multiplier**	**kW**	**Cumulative Multiplier**	**kW**	**Cumulative Multiplier**	**kW**	**Cumulative Multiplier**
Secondary		1.028905								
Sales	2,562,116		2,562,116							
Losses + Diversion	74,058		74,058							
Input to Primary	2,636,174		2,636,174	1.028905						
Primary		1.019432	2,636,174							
Primary Sales	401,943				401,943					
Primary Losses	59,037		51,226		7,811					
Input to Substation	3,097,154		2,687,400	1.048899	409,754	1.019432				
Substations		1.009829	2,687,400		409,754					
Substation Sales	108,062						108,062			
Substation Losses	31,504		26,414		4,027		1,062			
Input to Transmission	3,236,720		2,713,814	1.059208	413,781	1.029452	109,124	1.009829		
Transmission		1.020449	2,713,814		413,781		109,124			
Transmission Sales	79,285								79,285	
Losses	67,809		55,495		8,461		2,231		1,621	
System Input	3,383,814		2,769,309	1.080868	422,242	1.050503	111,356	1.030479	80,906	1.020449
Losses + Diversion	232,408		207,193		20,299		3,294		1,621	

TABLE A2-ENERGY LOSS MULTIPLIERS

	Total System		Secondary Service		Primary Service		Substation Service		Transmission Service	
SERVICE LEVEL	**kWh**	**Multiplier**	**kWh**	**Cumulative Multiplier**	**kWh**	**Cumulative Multiplier**	**kWh**	**Cumulative Multiplier**	**kWh**	**Cumulative Multiplier**
Secondary		1.023351								
Sales	11,401,521,000		11,401,521,000							
Losses + Diversion	266,234,512		266,234,512							
Input to Primary	11,667,755,512		11,667,755,512	1.023351						
Primary		1.011947	11,667,755,512							
Primary Sales	1,835,946,000				1,835,946,000					
Primary Losses	161,330,811		139,396,480		21,934,331					
Input to Substation	13,665,032,323		11,807,151,992	1.035577	1,857,880,331	1.011947				
Substations		1.009036	11,807,151,992		1,857,880,331					
Substation Sales	531,563,000						531,563,000			
Substation Losses	128,277,908		106,687,323		16,787,476		4,803,109			
Input to Transmission	14,324,873,231		11,913,839,316	1.044934	1,874,667,807	1.021091	536,366,109	1.009036		
Transmission		1.015651	11,913,839,316		1,874,667,807		536,366,109			
Transmission Sales	431,794,000								431,794,000	
Losses	230,949,767		186,457,983		29,339,558		8,394,418		6,757,808	
System Input	14,987,616,998		12,100,297,299	1.061288	1,904,007,365	1.037072	544,760,526	1.024828	438,551,808	1.015651
Losses + Diversion	786,792,998		698,776,299		68,061,365		13,197,526		6,757,808	

TABLE A3 - TRANSMISSION TRANSFORMER NO-LOAD LOSSES					
	VOLTAGE				
SUBSTATION	**HIGH SIDE**	**LOW SIDE**	**OA/FA/FOA**	**NO-LOAD LOSSES**	**ENERGY NO-LOAD LOSSES**
	KV	**KV**	**MVA**	**WATTS**	**KWH**
W.GRDNR7	345	161	240/320/400	175,227	1,539,194
STILWEL7	345	161	330/440/550	177,663	1,560,592
STILWEL7	345	161	330/440/550	73,448	645,167
HAWTH 7	345	161	300/400/500	211,000	1,853,424
HAWTH 7	345	161	300/400/501	80,018	702,878
HAWTH 7[1]	345	161	330/440/550	80,018	702,878
CRAIG 7	345	161	330/440/550	79,267	696,281
CRAIG 7	345	161	330/440/551	186,840	1,641,203
CRAIG 7	345	161	240/320/400	140,986	1,238,421
HAWTHRN5	161	69	30	53,200	467,309
HAWTHRN5	161	69	30	44,230	388,516
SWAVRLY5	161	69	20	40,500	355,752
DUNCAN 5	161	69	36/48/60	28,656	251,714
LBRTYST5	161	69	36/48/61	22,090	194,039
TOTAL				1,393,143	12,237,368

ESTIMATED (shaded cells: HAWTH 7[1] and first HAWTHRN5 loss values)

[1] ENERGIZED BUT NOT IN SERVICE

TABLE A4-34.5 KV TRANSFORMERS NO-LOAD LOSSES

SUBSTATION	VOLTAGE HIGH SIDE	VOLTAGE LOW SIDE	OA/FA/FOA	DEMAND NO-LOAD LOSSES	ENERGY NO-LOAD LOSSES
	KV	KV	MVA	WATTS	WH
WGARDNR5	161	34.5	15/20/25	37720	331,332,480
CAROLTN5	161	34.5	12/16	40500	355,752,000
BRUNSWK5	161	34.5	10/12.5/16.67	34960	307,088,640
SALSBRY5	161	34.5	10/12/16	34960	307,088,640
SALSBRY5	161	34.5	10/12.5/16.67	36110	317,190,240
SWAVRLY5	161	34.5	15/20/25	19363	170,084,592
NORTON-5	161	34.5	10/13.3/16.67	24340	213,802,560
CNTRVIL5	161	34.5	15/20/25	27900	245,073,600
CNTRVIL5	161	34.5	15/20/26	27900	245,073,600
S.OTTWA5	161	34.5	18/24/30	26000	228,384,000
S.OTTWA5	161	34.5	18/24/30	26800	235,411,200
S.OTTWA5	161	34.5	18/24/30	26000	228,384,000
WAGSTAF5	161	34.5	15/20/25	24700	216,964,800
PAOLA 5	161	34.5	15/20/25	37720	331,332,480
PAOLA 5	161	34.5	18/24/30	16602	145,831,968
TOTAL				441,575	3,878,794,800
ESTIMATED VALUE					

TABLE A5-GENERATOR STEP-UP TRANSFORMER NO-LOAD LOSSES

SUBSTATION	LOW SIDE	HIGH SIDE	RATE A	RATE B	DEMAND NO-LOAD LOSSES	PLANT HOURS OF OPERATION	ENERGY NO-LOAD LOSSES
	VOLTAGE						
	KV	KV	MVA	MVA	WATTS	HOURS	KWH
HAW G5 1	22.0	161.0	650	650	238,000	7921	1,885,198
MONTG1 1	22.0	161.0	195	195	143,170	8416	1,204,919
MONTG2 1	22.0	161.0	195	195	143,720	8416	1,209,548
MONTG3 1	18.0	161.0	175	175	120,857	8416	1,017,133
LAC G1 1	22.0	345.0	870	870	532,029	8077	4,297,198
LAC G2 1	24.0	345.0	724	724	468,572	8077	3,784,656
IAT G1 1	24.0	345.0	724	724	392,977	7753	3,046,751
HAWCT6 1	16.0	161.0	200	200	70,144	7921	555,611
HAWCT7 1	13.8	161.0	100	100	36,176	232	8,393
HAWCT8 1	13.8	161.0	100	100	35,444	232	8,223
HAW G9 1	13.8	161.0	147	147	161,000	7921	1,275,281
OSAWACT1	13.8	161.0	100	100	40,600	31	1,259
WG CT 1	13.8	161.0	100	100	38,554	93	3,586
WG CT 2	13.8	161.0	100	100	39,135	93	3,640
WG CT 3	13.8	161.0	100	100	38,752	93	3,604
WG CT 4	13.8	161.0	100	100	39,133	93	3,639
NE CT1112	13.8	161.0	107		73,720	113	8,330
NE CT1314	13.8	161.0	140		81,380	113	9,196
NE CT1516	13.8	161.0	140		83,519	113	9,438
NE CT1718	13.8	161.0	120		87,010	113	9,832
TOTAL					2,863,892		18,345,432

TABLE A6-TRANSMISSION TO DISTRIBUTION TRANSFORMERS										
	VOLTAGE				TRANSFORMER		NO-LOAD		LOAD	
SUBSTATION	LOW SIDE	HIGH SIDE	OA RATING	PEAK LOAD	NO-LOAD LOSSES	LOAD LOSSES	PEAK LOSSES	ENERGY LOSSES	NON-COINCIDENT PEAK LOSSES	ENERGY LOSSES
	KV	KV	MVA	MVA	WATTS	WATTS	KW	KWH	KW	KWH
SPRINT15	12.47	161	40	11.46	54,971	208,201	55.0	482,868	17.1	39,549
	12.47	161	40	11.46	54,971	208,201	55.0	482,868	17.1	39,549
QUARRY 5	12.47	161	12	5.92	16,491	62,460	16.5	144,861	15.2	35,179
QUARRY 5	12.47	161	12	5.92	16,491	62,460	16.5	144,861	15.2	35,179
PFLUMM 5	12.47	161	18	13.58	20,570	48,574	20.6	180,687	27.6	63,982
PFLUMM 5	12.47	161	18	7.32	20,740	48,566	20.7	182,180	8.0	18,587
BRKRIDG5	12.47	161	15	20.38	48,120	103,500	48.1	422,686	286.6	663,220
BRKRIDG5	12.47	161	15	19.24	48,120	103,500	48.1	422,686	255.4	591,098
BRKRIDG5	12.47	161	15	18.97	39,450	151,241	39.5	346,529	362.8	839,679
BRKRIDG5	12.47	161	15	18.70	39,450	151,241	39.5	346,529	352.6	815,947
BRKRIDG5	12.47	161	15	12.13	41,000	101,800	41.0	360,144	99.9	231,088
BRKRIDG5	12.47	161	15	18.20	41,000	101,800	41.0	360,144	224.8	520,235
BRKRIDG5	12.47	161	15	18.98	41,000	101,800	41.0	360,144	244.5	565,782
BRKRIDG5	12.47	161	15	14.27	41,000	101,800	41.0	360,144	138.2	319,819
SHAWNEE5	12.47	161	15	14.91	27,500	72,520	27.5	241,560	71.7	165,818
SHAWNEE5	12.47	161	15	16.66	27,250	70,000	27.3	239,364	86.4	199,832
REEDER 5	12.47	161	18	14.34	14,180	61,300	14.2	124,557	38.9	90,036
REEDER 5	12.47	161	18	24.16	15,730	58,550	15.7	138,172	105.5	244,105
LENEXAN5	12.47	161	15	10.59	37,560	106,934	37.6	329,927	79.9	184,844
LENEXAN5	12.47	161	15	10.59	37,560	106,934	37.6	329,927	79.9	184,844
LENEXAS5	12.47	161	15	19.97	37,400	109,321	37.4	328,522	290.5	672,282
LENEXAS5	12.47	161	15	19.97	37,400	109,321	37.4	328,522	290.5	672,282
LENEXAS5	12.47	161	18	18.60	14,474	62,136	14.5	127,140	66.3	153,541
OVERLPK5	12.47	161	18	25.07	14,094	62,711	14.1	123,802	121.6	281,519
OVERLPK5	12.47	161	15	19.84	30,109	63,664	30.1	264,477	111.4	257,748
OVERLPK5	12.47	161	18	19.06	14,294	61,817	14.3	125,558	69.3	160,402
KNLWRTH5	12.47	161	15	18.53	44,585	46,016	44.6	391,635	105.3	243,632
KNLWRTH5	12.47	161	15	18.53	44,585	46,077	44.6	391,635	105.4	243,955
KNLWRTH5	12.47	161	15	17.29	46,030	46,717	46.0	404,328	93.1	215,339
KNLWRTH5	12.47	161	15	17.29	46,030	46,690	46.0	404,328	93.0	215,215
KNLWRTH5	12.47	161	15	17.31	38,040	106,630	38.0	334,143	213.0	492,927
KNLWRTH5	12.47	161	15	17.31	38,040	106,630	38.0	334,143	213.0	492,927
KNLWRTH5	12.47	161	15	16.22	46,200	117,310	46.2	405,821	205.8	476,152
KNLWRTH5	12.47	161	15	16.22	46,200	117,310	46.2	405,821	205.8	476,152
CEDRCRK5	12.47	161	18	14.70	15,001	63,407	15.0	131,769	42.3	97,865
CEDRCRK5	12.47	161	18	5.43	20,731	48,310	20.7	182,101	4.4	10,174
ROEPARK5	12.47	161	15	18.61	37,900	122,300	37.9	332,914	282.4	653,474
ROEPARK5	12.47	161	15	18.61	37,900	122,920	37.9	332,914	283.8	656,787
ROEPARK5	12.47	161	15	15.12	37,900	122,300	37.9	332,914	186.3	431,074
ROEPARK5	12.47	161	15	15.12	37,900	122,920	37.9	332,914	187.2	433,259
ROEPARK5	12.47	161	18	21.23	14,258	60,968	14.3	125,242	84.8	196,271
MOONLT 5	12.47	161	18	16.38	17,720	68,512	17.7	155,652	56.7	131,295
MOONLT 5	12.47	161	18	21.50	13,929	62,888	13.9	122,352	89.7	207,635

TABLE A6-TRANSMISSION TO DISTRIBUTION TRANSFORMERS

	VOLTAGE				TRANSFORMER		NO-LOAD		LOAD	
SUBSTATION	LOW SIDE	HIGH SIDE	OA RATING	PEAK LOAD	NO-LOAD LOSSES	LOAD LOSSES	PEAK LOSSES	ENERGY LOSSES	NON-COINCIDENT PEAK LOSSES	ENERGY LOSSES
	KV	KV	MVA	MVA	WATTS	WATTS	KW	KWH	KW	KWH
COLLEGE5	12.47	161	18	15.67	14,060	64,420	14.1	123,503	48.8	112,983
COLLEGE5	12.47	161	18	22.05	14,199	60,980	14.2	124,724	91.5	211,768
COLLEGE5	12.47	161	18	24.97	21,426	50,947	21.4	188,206	98.0	226,888
MERRIAM5	12.47	161	15	18.19	48,250	100,220	48.3	423,828	220.9	511,317
MERRIAM5	12.47	161	15	18.19	48,250	100,220	48.3	423,828	220.9	511,317
MERRIAM5	12.47	161	15	18.61	40,820	113,270	40.8	358,563	261.4	604,899
MERRIAM5	12.47	161	15	18.61	40,820	113,270	40.8	358,563	261.4	604,899
MERRIAM5	12.47	161	15	17.99	40,820	113,270	40.8	358,563	244.4	565,570
MERRIAM5	12.47	161	15	17.99	40,820	113,720	40.8	358,563	245.4	567,817
GRNWOOD5	12.47	161	18	12.54	14,400	61,860	14.4	126,490	30.0	69,480
GRNWOOD5	12.47	161	18	24.24	15,195	69,594	15.2	133,473	126.2	292,074
GRNWOOD5	12.47	161	18	14.75	14,312	61,588	14.3	125,717	41.4	95,705
STILWEL5	12.47	161	18	7.96	14,020	60,490	14.0	123,152	11.8	27,376
RILEY 5	12.47	161	18	20.85	13,720	64,420	13.7	120,516	86.4	200,027
RILEY 5	12.47	161	18	20.38	22,314	71,093	22.3	196,006	91.1	210,907
RILEY 5	12.47	161	18	17.56	14,080	64,730	14.1	123,679	61.6	142,564
RILEY 5	12.47	161	24	26.50	21,217	94,497	21.2	186,370	115.2	266,617
SWITZER5	12.47	161	18	21.24	14,023	62,097	14.0	123,178	86.5	200,094
SWITZER5	12.47	161	18	14.19	15,130	66,672	15.1	132,902	41.4	95,888
SWITZER5	12.47	161	18	16.89	15,064	58,293	15.1	132,322	51.3	118,777
SWITZER5	12.47	161	18	19.02	21,276	49,490	21.3	186,888	55.3	127,877
	12.47	161	18	5.14	13,270	54,470	13.3	116,564	4.4	10,279
OXFORD 5	12.47	161	18	30.82	14,384	61,837	14.4	126,349	181.3	419,536
OXFORD 5	12.47	161	18	27.33	16,460	58,930	16.5	144,585	135.9	314,392
OLATHE 5	12.47	161	18	25.21	14,170	60,780	14.2	124,469	119.2	275,906
OLATHE 5	12.47	161	18	24.09	22,620	71,626	22.6	198,694	128.3	296,893
OLATHE 5	12.47	161	15	16.81	41,816	117,153	41.8	367,312	220.6	510,434
OLATHE 5	12.47	161	15	16.81	41,816	117,153	41.8	367,312	220.6	510,434
OLATHE 5	12.47	161	15	9.60	40,800	107,600	40.8	358,387	66.1	152,990
OLATHE 5	12.47	161	15	9.60	40,800	107,600	40.8	358,387	66.1	152,990
OLATHE 5	12.47	161	18	8.55	13,700	55,050	13.7	120,341	12.4	28,744
ANTIOCH5	12.47	161	18	10.37	19,334	43,951	19.3	169,830	14.6	33,758
ANTIOCH5	12.47	161	18	6.74	21,629	51,441	21.6	189,989	7.2	16,691
MURLEN 5	12.47	161	18	20.84	17,560	68,781	17.6	154,247	92.2	213,363
MURLEN 5	12.47	161	18	20.73	14,080	55,340	14.1	123,679	73.4	169,861
MURLEN 5	12.47	161	18	17.06	13,623	62,794	13.6	119,664	56.4	130,536
REDEL 5	12.47	161	18	18.80	24,737	93,690	24.7	217,291	102.2	236,519
REDEL 5	12.47	161	18	12.20	71,721	61,337	71.7	629,997	28.2	65,207
BUCYRUS5	12.47	161	18	7.93	13,280	52,490	13.3	116,652	10.2	23,576
BUCYRUS5	12.47	161	18	8.56	24,737	93,690	24.7	217,291	21.2	49,034
GRAND W5	13.2	161	15	11.39	39,800	107,432	39.8	349,603	92.9	215,026
GRAND W5	13.2	161	15	14.06	39,800	107,432	39.8	349,603	141.6	327,652
GRAND 5	13.2	161	24	11.23	72,120	142,401	72.1	633,502	46.8	108,228

	VOLTAGE				TRANSFORMER		NO-LOAD		LOAD	
SUBSTATION	LOW SIDE	HIGH SIDE	OA RATING	PEAK LOAD	NO-LOAD LOSSES	LOAD LOSSES	PEAK LOSSES	ENERGY LOSSES	NON-COINCIDENT PEAK LOSSES	ENERGY LOSSES
	KV	KV	MVA	MVA	WATTS	WATTS	KW	KWH	KW	KWH
GRAND 5	13.2	161	24	11.23	72,120	140,518	72.1	633,502	46.1	106,797
GRAND 5	13.2	161	24	11.60	72,120	142,401	72.1	633,502	49.9	115,478
GRAND 5	13.2	161	24	11.60	72,120	142,401	72.1	633,502	49.9	115,478
NAVY 5	13.2	161	18	12.16	14,020	68,250	14.0	123,152	31.1	72,082
CROSTWN5	13.2	161	15	17.74	43,920	90,320	43.9	385,793	189.4	438,284
CROSTWN5	13.2	161	15	17.74	43,920	90,320	43.9	385,793	189.4	438,284
CROSTWN5	13.2	161	15	10.90	38,740	108,385	38.7	340,292	85.8	198,487
CROSTWN5	13.2	161	15	10.90	38,740	108,385	38.7	340,292	85.8	198,487
CROSTWN5	13.2	161	15	16.85	38,740	108,385	38.7	340,292	205.2	474,764
CROSTWN5	13.2	161	15	16.85	38,740	108,385	38.7	340,292	205.2	474,764
	13.2	161	15	9.16	40,480	78,075	40.5	355,576	43.7	101,068
CROSTWN5	13.2	161	15	9.16	40,480	122,660	40.5	355,576	68.6	158,783
TERRACE5	13.2	161	18	8.97	14,623	63,433	14.6	128,448	15.8	36,455
TERRACE5	13.2	161	18	18.69	14,643	60,890	14.6	128,624	65.6	151,922
TERRACE5	13.2	161	18	10.89	14,290	69,850	14.3	125,523	25.6	59,167
CHOUTEU5	13.2	161	18	17.54	24,737	93,690	24.7	217,291	89.0	205,878
BLUEVLY5	13.2	161	15	0.06	38,900	111,320	38.9	341,698	0.0	6
BLUEVLY5	13.2	161	15	0.06	38,900	111,320	38.9	341,698	0.0	6
BLUEVLY5	13.2	161	36	20.63	83,600	298,000	83.6	734,342	97.9	226,470
BLUEVLY5	13.2	161	48	37.52	72,160	172,640	72.2	633,853	105.5	244,110
BLUEVLY5	13.2	161	36	15.59	45,850	185,560	45.9	402,746	34.8	80,533
NEAST 5	13.2	161	25	34.86	53,000	96,530	53.0	465,552	187.7	434,347
NEAST 5	13.2	161	25	38.52	49,200	97,750	49.2	432,173	232.1	537,044
NEAST 5	13.2	161	25	29.20	47,750	94,850	47.8	419,436	129.4	299,449
NEAST 5	13.2	161	18	12.37	15,590	59,050	15.6	136,943	27.9	64,538
NEAST 5	13.2	161	18	24.64	14,340	62,780	14.3	125,963	117.6	272,244
HAWTHRN5	13.2	161	40	12.10	148,375	303,900	148.4	1,303,326	27.8	64,355
HAWTHRN5	13.2	161	40	24.73	146,960	313,000	147.0	1,290,897	119.6	276,868
#N/A			8	1.78	10,994	41,640	11.0	96,574	2.1	4,771
#N/A			6	2.13	8,246	31,230	8.2	72,430	3.9	9,108
#N/A			6	2.12	8,246	31,230	8.2	72,430	3.9	9,023
#N/A			6	4.29	8,246	31,230	8.2	72,430	16.0	36,948
#N/A			6	4.15	8,246	31,230	8.2	72,430	14.9	34,575
COURTNY2	12.47	69	3	4.12	18,267	35,581	18.3	160,457	67.1	155,300
	12.47	69	3	4.12	18,267	35,581	18.3	160,457	67.1	155,300
BLUMILS5	12.47	161	12	6.17	13,370	33,500	13.4	117,442	8.9	20,495
BLUMILS5	12.47	161	12	6.17	57,937	80,891	57.9	508,919	21.4	49,489
BLUSPRG2	12.47	69	7.5	3.92	19,800	51,342	19.8	173,923	14.0	32,458
SUGRCRK2	4.16	69	2	1.95	2,220	5,656	2.2	19,500	5.4	12,443
SUGRCRK2	4.16	69	2	1.95	2,220	5,656	2.2	19,500	5.4	12,443
SUGRCRK2	4.16	69	3.75	1.95	4,163	10,606	4.2	36,563	2.9	6,637
DUNCNRD2	12.47	69	18	15.51	14,200	60,080	14.2	124,733	44.6	103,231
BRMGHAM5	12.47	161	12	10.23	26,600	92,000	26.6	233,654	66.9	154,731

TABLE A6-TRANSMISSION TO DISTRIBUTION TRANSFORMERS										
	VOLTAGE				TRANSFORMER		NO-LOAD		LOAD	
SUBSTATION	LOW SIDE	HIGH SIDE	OA RATING	PEAK LOAD	NO-LOAD LOSSES	LOAD LOSSES	PEAK LOSSES	ENERGY LOSSES	NON-COINCIDENT PEAK LOSSES	ENERGY LOSSES
	KV	KV	MVA	MVA	WATTS	WATTS	KW	KWH	KW	KWH
BARRY 5	12.47	161	18	27.57	14,376	57,658	14.4	126,279	135.3	313,032
BARRY 5	12.47	161	18	12.39	14,197	60,174	14.2	124,706	28.5	65,979
AVONDAL5	13.2	161	15	17.19	39,460	126,891	39.5	346,617	250.0	578,484
AVONDAL5	12.47	161	15	13.45	39,460	126,891	39.5	346,617	153.0	354,148
AVONDAL5	12.47	161	15	13.91	45,561	114,567	45.6	400,208	147.8	341,997
AVONDAL5	13.2	161	15	22.86	45,561	114,567	45.6	400,208	399.1	923,679
AVONDAL5	13.2	161	15	21.45	46,400	105,300	46.4	407,578	323.0	747,467
AVONDAL5	12.47	161	15	18.30	46,400	105,300	46.4	407,578	235.1	544,051
TIFFANY5	12.47	161	15	25.12	30,790	82,100	30.8	270,459	230.3	532,844
TIFFANY5	12.47	161	18	7.39	21,524	49,354	21.5	189,067	8.3	19,252
WETHRBY5	13.2	161	15	7.06	15,724	60,641	15.7	138,120	20.2	46,632
	13.2	161	15	7.06	15,724	60,641	15.7	138,120	20.2	46,632
WETHRBY5	12.47	161	18	17.05	47,250	105,400	47.3	415,044	94.6	218,849
WETHRBY5	12.47	161	15	20.03	38,636	110,934	38.6	339,379	296.7	686,650
WETHRBY5	12.47	161	15	16.39	38,636	110,934	38.6	339,379	198.7	459,760
CLAYCM15	12.47	161	15	4.80	39,920	108,515	39.9	350,657	16.7	38,573
CLAYCM15	12.47	161	15	9.67	39,920	108,515	39.9	350,657	67.6	156,549
		161	18	14.47	24,737	93,690	24.7	217,291	60.5	140,116
CLAYCM25	12.47	161	30	22.00	47,368	94,603	47.4	416,081	50.9	117,736
CLAYCM15	12.47	161	30	22.00	20,270	80,550	20.3	178,052	43.3	100,246
LINECRK5	12.47	161	18	11.43	15,083	59,261	15.1	132,489	23.9	55,299
	12.47	161	18	11.43	24,737	93,690	24.7	217,291	37.8	87,426
LINECRK5	12.47	161	18	11.43	13,931	60,022	13.9	122,370	24.2	56,009
SHOLCRK5	12.47	161	18	8.39	21,860	44,700	21.9	192,018	9.7	22,474
SHOLCRK5	12.47	161	18	8.39	24,737	93,690	24.7	217,291	20.4	47,106
RANDLPH5	12.47	161	18	11.71	14,020	60,770	14.0	123,152	25.7	59,519
RANDLPH5	12.47	161	15	11.71	14,020	60,770	14.0	123,152	37.0	85,708
GLADSTN5	12.47	161	15	20.39	20,614	78,075	20.6	181,076	216.4	500,792
GLADSTN5	12.47	161	15	24.20	20,614	78,075	20.6	181,076	304.8	705,430
GLADSTN5	12.47	161	15	16.89	46,181	97,026	46.2	405,654	184.5	427,028
GLADSTN5	12.47	161	15	16.27	46,181	98,636	46.2	405,654	174.1	402,828
GLADSTN5	12.47	161	18	17.52	44,800	128,576	44.8	393,523	182.7	422,839
GLADSTN5	12.47	161	18	20.38	44,800	128,576	44.8	393,523	247.2	572,156
NKANCTY5	13.2	161	18	6.71	15,337	59,808	15.3	134,720	8.3	19,234
NKANCTY5	13.2	161	18	17.55	14,246	59,725	14.2	125,137	56.8	131,391
NKANCTY5	13.2	161	15	6.71	47,800	10,763	47.8	419,875	3.2	7,476
NKANCTY5	13.2	161	15	19.47	47,800	10,763	47.8	419,875	27.2	62,947
RIVRSID5	12.47	161	12	10.18	26,600	92,000	26.6	233,654	66.2	153,222
RIVRSID5	12.47	161	18	17.24	15,561	60,195	15.6	136,688	55.2	127,788
STHTOWN5	13.2	161	15	17.50	42,240	100,800	42.2	371,036	205.7	475,990
STHTOWN5	13.2	161	15	17.50	42,240	100,800	42.2	371,036	205.7	475,990
STHTOWN5	13.2	161	15	19.10	48,820	100,900	48.8	428,835	163.6	378,596
STHTOWN5	13.2	161	15	19.35	30,450	64,533	30.5	267,473	107.4	248,520

TABLE A6-TRANSMISSION TO DISTRIBUTION TRANSFORMERS										
	VOLTAGE				TRANSFORMER		NO-LOAD		LOAD	
SUBSTATION	LOW SIDE	HIGH SIDE	OA RATING	PEAK LOAD	NO-LOAD LOSSES	LOAD LOSSES	PEAK LOSSES	ENERGY LOSSES	NON-COINCIDENT PEAK LOSSES	ENERGY LOSSES
	KV	KV	MVA	MVA	WATTS	WATTS	KW	KWH	KW	KWH
STHTOWN5	13.2	161	15	20.75	40,700	176,640	40.7	357,509	338.0	782,245
STHTOWN5	13.2	161	15	9.93	38,636	110,934	38.6	339,379	72.9	168,591
	13.2	161	15	9.93	38,636	110,934	38.6	339,379	72.9	168,591
SWOPE S5	12.47	161	18	13.26	13,842	60,248	13.8	121,588	32.7	75,663
SWOPE N5	12.47	161	18	8.07	14,110	64,370	14.1	123,942	12.9	29,942
FOREST 5	13.2	161	15	15.01	14,350	64,570	14.4	126,050	64.7	149,627
FOREST 5	13.2	161	15	18.90	20,614	112,750	20.6	181,076	268.5	621,368
FOREST 5	13.2	161	15	20.05	20,614	112,750	20.6	181,076	302.2	699,285
FOREST 5	13.2	161	18	22.16	16,417	63,754	16.4	144,207	96.6	223,616
LVISTAE5	12.47	161	18	17.35	16,417	63,754	16.4	144,207	59.2	137,076
LVISTAE5	12.47	161	15	26.37	20,614	78,075	20.6	181,076	361.9	837,613
LVISTAE5	12.47	161	15	17.78	20,614	78,075	20.6	181,076	164.5	380,791
LVISTAW5	12.47	161	18	15.29	13,780	57,987	13.8	121,044	41.8	96,828
TOMHAWK5	12.47	161	15	23.68	40,100	107,223	40.1	352,238	400.8	927,599
TOMHAWK5	12.47	161	15	23.17	40,100	107,223	40.1	352,238	383.8	888,074
	12.47	161	15	9.10	13,250	52,680	13.3	116,388	29.1	67,303
TOMHAWK5	12.47	161	15	9.10	13,250	52,680	13.3	116,388	29.1	67,303
TOMHAWK5	12.47	161	18	21.38	13,976	63,810	14.0	122,765	90.0	208,334
HICKMAN5	12.47	161	15	10.29	42,300	92,336	42.3	371,563	65.2	150,838
HICKMAN5	12.47	161	15	11.10	42,300	92,336	42.3	371,563	75.8	175,520
HICKMAN5	12.47	161	18	21.51	13,230	52,310	13.2	116,212	74.7	172,870
HICKMAN5	12.47	161	18	14.37	14,350	64,570	14.4	126,050	41.2	95,236
LEEDS 5	13.2	161	15	20.37	45,400	102,000	45.4	398,794	282.2	652,967
LEEDS 5	13.2	161	15	16.68	45,400	102,000	45.4	398,794	189.2	437,826
LEEDS 5	13.2	161	15	15.02	41,300	123,800	41.3	362,779	186.2	430,893
LEEDS 5	13.2	161	15	2.73	41,300	123,800	41.3	362,779	6.2	14,235
LEEDS 5	13.2	161	15	27.61	41,300	123,800	41.3	362,779	629.2	1,456,003
LEEDS 5	13.2	161	15	23.56	41,300	100,700	41.3	362,779	372.6	862,361
MARTCIT5	12.47	161	18	5.80	13,970	55,160	14.0	122,712	5.7	13,254
MARTCIT5	12.47	161	18	29.75	14,629	57,514	14.6	128,501	157.1	363,582
MARTCIT5	12.47	161	18	24.20	14,121	60,844	14.1	124,039	110.0	254,509
MIDTOWN5	13.2	161	25	32.31	56,550	87,260	56.6	496,735	145.8	337,295
MIDTOWN5	13.2	161	15	20.57	45,667	88,953	45.7	401,139	250.9	580,682
MIDTOWN5	13.2	161	15	19.13	45,667	88,677	45.7	401,139	216.3	500,668
MIDTOWN5	13.2	161	15	21.68	47,058	94,350	47.1	413,357	295.6	684,178
MIDTOWN5	13.2	161	15	19.76	47,058	94,603	47.1	413,357	246.3	569,886
MIDTOWN5	13.2	161	15	27.82	47,000	100,900	47.0	412,848	520.6	1,204,798
MIDTOWN5	13.2	161	15	17.48	47,000	100,900	47.0	412,848	205.5	475,645
BRKRIDG5	12.47	161	12	10.07	13,370	33,500	13.4	117,442	23.6	54,594
BRKRIDG5	12.47	161	12	6.52	13,320	33,940	13.3	117,003	10.0	23,187
#N/A	12.47	161	15	20.51	175,227	326,836	175.2	1,539,194	611.1	1,414,096
#N/A	12.47	34.5	1.5	1.17	2,061	7,808	2.1	18,108	4.8	10,993
#N/A	12.47	34.5	3	2.44	4,123	15,615	4.1	36,215	10.3	23,905

TABLE A6-TRANSMISSION TO DISTRIBUTION TRANSFORMERS

	VOLTAGE				TRANSFORMER		NO-LOAD		LOAD	
SUBSTATIO N	LOW SIDE	HIGH SIDE	OA RATIN G	PEAK LOAD	NO-LOAD LOSSES	LOAD LOSSES	PEAK LOSSES	ENERGY LOSSES	NON-COINCIDENT PEAK LOSSES	ENERGY LOSSES
	KV	KV	MVA	MVA	WATTS	WATTS	KW	KWH	KW	KWH
#N/A	13.2	161	18	17.13	15,085	63,057	15.1	132,507	57.1	132,161
#N/A		34.5	3.75	3.23	5,154	19,519	5.2	45,269	14.5	33,512
#N/A	12.47	34.5	3.75	2.93	4,872	20,674	4.9	42,796	12.6	29,208
#N/A	12.47	34.5	3.75	2.93	4,243	17,355	4.2	37,271	10.6	24,519
#N/A		34.5	3.75	2.66	5,154	19,519	5.2	45,269	9.8	22,728
#N/A	12.47	34.5	3	1.12	4,123	15,615	4.1	36,215	2.2	5,037
#N/A	12.47	34.5	3	1.12	4,123	15,615	4.1	36,215	2.2	5,037
#N/A	12.47	34.5	3	2.66	4,123	15,615	4.1	36,215	12.3	28,410
#N/A	12.47	34.5	1.5	1.06	2,061	7,808	2.1	18,108	3.9	9,023
#N/A	12.47	34.5	1.5	1.06	2,061	7,808	2.1	18,108	3.9	9,023
S.OTTWA5	12.47	34.5	7.5	1.91	10,307	39,038	10.3	90,538	2.5	5,859
S.OTTWA5	12.47	34.5	3.75	1.91	5,154	19,519	5.2	45,269	5.1	11,718
#N/A	12.47	34.5	1.5	1.39	2,061	7,808	2.1	18,108	6.7	15,515
#N/A	12.47	34.5	3.75	0.43	5,154	19,519	5.2	45,269	0.3	594
#N/A	12.47	34.5	3	0.43	4,123	15,615	4.1	36,215	0.3	742
#N/A	12.47	34.5	7.5	5.29	10,307	39,038	10.3	90,538	19.4	44,944
#N/A	12.47	34.5	7.5	2.96	10,307	39,038	10.3	90,538	6.1	14,072
#N/A	12.47	34.5	7.5	2.96	10,307	39,038	10.3	90,538	6.1	14,072
#N/A		34.5	0.75	0.59	1,031	3,904	1.0	9,054	2.4	5,591
#N/A	12.47	34.5	0.6	0.59	825	3,123	0.8	7,243	3.0	6,988
#N/A		34.5	1.5	1.17	2,061	7,808	2.1	18,108	4.8	10,993
#N/A		34.5	6	2.82	8,246	31,230	8.2	72,430	6.9	15,965
		34.5	7.5	2.82	10,307	39,038	10.3	90,538	5.5	12,772
#N/A		34.5	3.75	1.80	5,154	19,519	5.2	45,269	4.5	10,407
#N/A	12.47	34.5	3.75	2.45	5,154	19,519	5.2	45,269	8.3	19,281
	12.47	34.5	3.75	2.45	5,154	19,519	5.2	45,269	8.3	19,281
#N/A	34	34.5	7.5	3.54	10,307	39,038	10.3	90,538	8.7	20,126
#N/A	34	34.5	7.5	3.54	10,307	39,038	10.3	90,538	8.7	20,126
#N/A		34.5	7.5	1.93	10,307	39,038	10.3	90,538	2.6	5,982
#N/A		34.5	7.5	3.77	10,307	39,038	10.3	90,538	9.9	22,827
#N/A	12.47	34.5	3.75	1.49	5,154	19,519	5.2	45,269	3.1	7,131
#N/A	12.47	34.5	1.5	0.95	2,061	7,808	2.1	18,108	3.1	7,247
#N/A	12.47	34.5	1.5	0.43	2,061	7,808	2.1	18,108	0.6	1,485
#N/A	12.47	34.5	1.5	0.43	2,061	7,808	2.1	18,108	0.6	1,485
#N/A	12.47	34.5	3.75	2.82	4,833	21,382	4.8	42,453	12.1	27,982
#N/A	12.47	34.5	3.75	2.82	5,154	19,519	5.2	45,269	11.0	25,544
CENTENL5	13.2	161	18	11.88	15,130	66,672	15.1	132,902	29.0	67,210
CENTENL5	13.2	161	18	19.02	19,478	43,619	19.5	171,095	48.7	112,707
	12.47	34.5	3.75	1.38	2,220	5,656	2.2	19,500	0.8	1,773
#N/A	12.47	34.5	3.75	1.38	2,220	5,656	2.2	19,500	0.8	1,773
#N/A		34.5	3	1.93	4,123	15,615	4.1	36,215	6.5	14,956
#N/A		34.5	3.75	1.71	5,154	19,519	5.2	45,269	4.1	9,393
#N/A		34.5	3.75	0.71	5,154	19,519	5.2	45,269	0.7	1,619

TABLE A6-TRANSMISSION TO DISTRIBUTION TRANSFORMERS

	VOLTAGE				TRANSFORMER		NO-LOAD		LOAD	
SUBSTATIO N	LOW SIDE	HIGH SIDE	OA RATIN G	PEAK LOAD	NO-LOAD LOSSES	LOAD LOSSES	PEAK LOSSES	ENERGY LOSSES	NON-COINCIDENT PEAK LOSSES	ENERGY LOSSES
	KV	KV	MVA	MVA	WATTS	WATTS	KW	KWH	KW	KWH
#N/A		34.5	10	12.96	13,743	52,050	13.7	120,717	87.4	202,317
#N/A		34.5	0.5	0.61	687	2,603	0.7	6,036	3.9	8,964
#N/A		34.5	3	0.54	4,123	15,615	4.1	36,215	0.5	1,171
#N/A		34.5	3.75	2.11	5,154	19,519	5.2	45,269	6.2	14,301
#N/A		69	2	0.89	2,749	10,410	2.7	24,143	2.1	4,771
#N/A		69	3.75	0.72	5,154	19,519	5.2	45,269	0.7	1,665
#N/A	12.47	34.5	1.5	1.58	2,061	7,808	2.1	18,108	8.7	20,047
#N/A	12.47	34.5	1.5	1.58	2,061	7,808	2.1	18,108	8.7	20,047
#N/A		34.5	3.75	2.96	5,154	19,519	5.2	45,269	12.2	28,143
#N/A		34.5	3	2.14	4,123	15,615	4.1	36,215	7.9	18,388
#N/A		34.5	7.5	1.94	10,307	39,038	10.3	90,538	2.6	6,045
#N/A		34.5	7.5	1.94	10,307	39,038	10.3	90,538	2.6	6,045
#N/A	12.47	34.5	7.5	3.36	10,307	39,038	10.3	90,538	7.8	18,132
#N/A	12.47	34.5	7.5	3.36	10,307	39,038	10.3	90,538	7.8	18,132
#N/A	12.47	34.5	7.5	2.14	7,284	38,219	7.3	63,983	3.1	7,201
#N/A		69	3	2.06	4,123	15,615	4.1	36,215	7.4	17,039
#N/A		34.5	6	3.16	8,246	31,230	8.2	72,430	8.7	20,047
#N/A		34.5	3.75	1.72	5,154	19,519	5.2	45,269	4.1	9,503
#N/A		34.5	3.75	1.72	5,154	19,519	5.2	45,269	4.1	9,503
#N/A		34.5	3.75	0.83	5,154	19,519	5.2	45,269	1.0	2,213
#N/A		34.5	3.75	0.83	5,154	19,519	5.2	45,269	1.0	2,213
#N/A		34.5	3.75	1.84	5,154	19,519	5.2	45,269	4.7	10,875
	12.47	34.5	3.75	2.07	27,500	72,520	27.5	241,560	22.1	51,137
	12.47	34.5	3.75	2.07	27,500	72,520	27.5	241,560	22.1	51,137
TOTALS			3,901.6	3,518.72			7,317	64,275,803	26,465	61,244,424

ESTIMATED

TABLE A7-DISTRIBUTION TO DISTRIBUTION TRANSFORMERS

		VOLTAGE		NO-LOAD LOSSES		LOAD LOSSES	
SUBSTATION	CAPACITY	HIGH SIDE	LOW SIDE	DEMAND	ENERGY	DEMAND	ENERGY
	KVA	KV	KV	KW	KWH	KW	KWH
BANK 618	1,500	12,470	13,200	4.5	39,528	9.6	22,216
BANK 614	1,500	12,470	4,160	4.5	39,528	9.6	22,216
JO-BA-10491	6,000	13,200	12,470	18.0	158,112	38.4	88,865
JO-BA-851425	1,500	13,200	4,160	4.5	39,528	9.6	22,216
BANK#619	1,500	13,200	4,160	4.5	39,528	9.6	22,216
JO-A-721	500	12,470	4,160	1.5	13,176	3.2	7,405
JO-BA-851425	1,500	12,470	4,160	4.5	39,528	9.6	22,216
JO-BA-940813	2,250	13,200	12,470	6.8	59,292	14.4	33,324
JA-BA-9729	6,000	13,200	12,470	18.0	158,112	38.4	88,865
JO-BA-045190	6,000	12,470	13,200	18.0	158,112	38.4	88,865
JO-B-10113	2,000	12,470	13,200	6.0	52,704	12.8	29,622
JO-BA-9764	2,000	12,470	13,200	6.0	52,699	12.8	29,619
JO-BA-9761	2,000	12,470	13,200	6.0	52,704	12.8	29,622
JA-BA-13726	6,000	13,200	12,470	18.0	158,112	38.4	88,865
JA-BA-11784	6,000	12,470	13,200	18.0	158,112	38.4	88,865
JO-BA-8960	6,000	13,200	12,470	18.0	158,112	38.4	88,865
JO-BA-8922	6,000	12,470	13,200	18.0	158,112	38.4	88,865
JA-B-A-679	10,500	12,470	13,200	31.5	276,696	67.2	155,514
JA-B-A-16767	1,500	12,470	13,200	4.5	39,528	9.6	22,216
JA-B-890579	6,000	13,200	12,470	18.0	158,112	38.4	88,865
JA-B-17492	6,000	12,470	13,200	18.0	158,112	38.4	88,865
BANK 701	500	13,200	4,160	1.5	13,176	3.2	7,405
JA-BA-13646	10,500	12,470	13,200	31.5	276,696	67.2	155,514
JA-BA-18627	2,250	12,470	13,200	6.8	59,292	14.4	33,324
JA-BA-16527	6,000	12,470	13,200	18.0	158,112	38.4	88,865
JA-BA-16690	10,500	12,470	13,200	31.5	276,696	67.2	155,514
JA-BA-900952	10,500	12,470	13,200	31.5	276,696	67.2	155,514
JA-BA-19022	11,250	12,470	13,200	33.8	296,460	72.0	166,622
JA-BA-11737	10,500	12,470	13,200	31.5	276,696	67.2	155,514
JA-BA-16578	10,500	12,470	13,200	31.5	276,696	67.2	155,514
JA-BA-19182	10,500	13,200	12,470	31.5	276,696	67.2	155,514
JA-B-16059	6,000	13,200	12,470	18.0	158,112	38.4	88,865
514	0	13,200	4,160	0.0	0	0.0	0
513	45	13,200	4,160	0.1	1,186	0.3	666
509	0	13,200	4,160	0.0	0	0.0	0
515	0	13,200	4,160	0.0	0	0.0	0
JA-BA-950991	501	12,470	13,200	1.5	13,202	3.2	7,420
BANK-632	1,500	13,200	4,160	4.5	39,528	9.6	22,216
542	45	13,200	4,160	0.1	1,186	0.3	666
575	45	13,200	4,160	0.1	1,186	0.3	666
576	45	13,200	4,160	0.1	1,186	0.3	666
588	45	13,200	4,160	0.1	1,186	0.3	666

TABLE A7-DISTRIBUTION TO DISTRIBUTION TRANSFORMERS

		VOLTAGE		NO-LOAD LOSSES		LOAD LOSSES	
SUBSTATION	CAPACITY	HIGH SIDE	LOW SIDE	DEMAND	ENERGY	DEMAND	ENERGY
	KVA	KV	KV	KW	KWH	KW	KWH
587	45	13,200	4,160	0.1	1,186	0.3	666
539	2,001	13,200	4,160	6.0	52,730	12.8	29,637
540	45	13,200	4,160	0.1	1,186	0.3	666
541	45	13,200	4,160	0.1	1,186	0.3	666
B-588	1,500	13,200	4,160	4.5	39,528	9.6	22,216
558	45	13,200	4,160	0.1	1,186	0.3	666
BANK 627	1,500	13,200	4,160	4.5	39,528	9.6	22,216
BANK 631	1,500	13,200	4,160	4.5	39,528	9.6	22,216
BANK 628	1,500	13,200	4,160	4.5	39,528	9.6	22,216
BANK 629	1,500	13,200	4,160	4.5	39,528	9.6	22,216
NC-4022	100	13,200	4,160	0.3	2,635	0.6	1,481
NC-511	100	13,200	4,160	0.3	2,635	0.6	1,481
BANK 603	1,500	13,200	4,160	4.5	39,528	9.6	22,216
BANK 711	1,500	13,200	4,160	4.5	39,528	9.6	22,216
BANK 686	501	13,200	4,160	1.5	13,202	3.2	7,420
589	45	13,200	4,160	0.1	1,186	0.3	666
536	45	13,200	4,160	0.1	1,186	0.3	666
535	45	13,200	4,160	0.1	1,186	0.3	666
548	45	13,200	4,160	0.1	1,186	0.3	666
573	45	13,200	4,160	0.1	1,186	0.3	666
574	45	13,200	4,160	0.1	1,186	0.3	666
590	45	13,200	4,160	0.1	1,186	0.3	666
557	45	13,200	4,160	0.1	1,186	0.3	666
544	45	13,200	4,160	0.1	1,186	0.3	666
CL-B-880476	10,500	13,200	12,470	31.5	276,696	67.2	155,514
NC-BA-5181	10,500	12,470	13,200	31.5	276,696	67.2	155,514
NC-BA-6397	10,500	13,200	12,470	31.5	276,696	67.2	155,514
NC-BA-5551	6,000	13,200	12,470	18.0	158,112	38.4	88,865
BANK-650	1,500	13,200	4,160	4.5	39,528	9.6	22,216
BANK-901	1,500	13,200	4,160	4.5	39,528	9.6	22,216
BANK 687	1,500	4,160	13,200	4.5	39,528	9.6	22,216
TOTALS				687.8	6,041,533	1,467.3	3,395,579

TABLE A8-CORONA LOSSES

		LOSSS			DEMAND LOSSES		ENERGY LOSSES		TOTAL LOSSES	
VOLTAGE	LENGTH OF CIRCUITS	NO RAIN	WITH RAIN	HOURS OF RAIN	NO RAIN	WITH RAIN	NO RAIN	RAIN	DEMAND	ENERGY
KV	MILES	KW/MILE	KW/MILE	HOURS	KW	KW	KWH	KWH	KW	KWH
69	95.3	0	0.008	115	0.0	0.8	0	88	0.0	88
161	1009.8	0.01	0.837	115	10.1	845.2	87,540	97,198	10.1	184,738
345	455.5	0.314	28.101	115	143.0	12800.0	1,239,667	1,472,001	143.0	2,711,668
								TOTALS	153.1	2,896,493