INTRODUCTION

AEP Texas Inc. (AEP Texas or Company) presents this Energy Efficiency Plan and Report (EEPR) to comply with Public Utility Commission of Texas (Commission) 16 Tex. Admin. Code §§ 25.181, 25.182 and 25.183 (TAC) (EE Rule), which implement the Public Utility Regulatory Act (PURA) § 39.905.

As mandated by PURA § 39.905, the EE Rule requires that each investor-owned electric transmission and distribution utility (TDU) achieve the following demand reduction goals through market-based standard offer programs (SOPs) and targeted market transformation programs (MTPs). 16 TAC § 25.181(e)(1) provides in pertinent part as follows:

(e)(1) An electric utility shall administer a portfolio of energy efficiency programs to acquire, at a minimum, the following:

> (A) Beginning with the 2013 program year, until the trigger described in subparagraph (B) of this paragraph is reached, the utility shall acquire a 30% reduction of its annual growth in demand of residential and commercial customers.
>
> (B) If the demand reduction goal to be acquired by a utility under subparagraph (A) of this paragraph is equivalent to at least four-tenths of 1% of its summer weather-adjusted peak demand for the combined residential and commercial customers for the previous program year, the utility shall meet the energy efficiency goal described in subparagraph (C) of this paragraph for each subsequent program year.
>
> (C) Once the trigger described in subparagraph (B) of this paragraph is reached, the utility shall acquire four-tenths of 1% of its summer weather-adjusted peak demand for the combined residential and commercial customers for the previous program year.
>
> (D) Except as adjusted in accordance with subsection (u) of this section, a utility's demand reduction goal in any year shall not be lower than its goal for the prior year, unless the commission establishes a goal for a utility pursuant to paragraph (2) of this subsection.

The EE Rule includes specific requirements related to the implementation of SOPs and MTPs that control the manner in which TDUs must administer their portfolio of energy efficiency programs in order to achieve their mandated annual demand reduction goals. AEP Texas' plans enable it to meet its statutory goals through implementation of energy efficiency programs in a manner that complies with PURA § 39.905 and the EE Rule. This EEPR covers the periods of time required in the EE Rule. The following section describes the information that is contained in each of the subsequent sections and appendices.

EEPR ORGANIZATION

This EEPR consists of an Executive Summary, Energy Efficiency Plan, Energy Efficiency Report, a list of acronyms, and three appendices.

Executive Summary

- Summarizes AEP Texas' plans for achieving its goals and projected energy efficiency savings for program years 2023 and 2024 and highlights AEP Texas' achievements for Program Year (PY) 2022.

Energy Efficiency Plan

- Section I describes the program portfolio. It details how programs will be implemented, presents related informational and outreach activities, and provides an introduction to any programs not included in the 2022 EEPR.
- Section II describes the targeted customer classes, the estimated size of each class and the method of determining those class sizes.
- Section III presents the energy and demand goals and projected savings for the prescribed planning period detailed by program for each customer class.
- Section IV describes the proposed energy efficiency budgets for the prescribed planning period detailed by program for each customer class.

Energy Efficiency Report

- Section V documents the demand reduction goal for each of the previous five years (2018-2022) based on its weather-adjusted peak demand and actual savings achieved for those years.
- Section VI compares the projected energy and demand savings to its reported and verified savings by program for PY 2021 and 2022.
- Section VII details the incentive and administration expenditures for each of the previous five years (2018-2022) detailed by program for each customer class.
- Section VIII compares the actual 2022 expenditures with the 2022 budget by program for each customer class. It also explains any cost differences of more than 10% from the overall program budget and from each program budget.
- Section IX describes the results from the MTPs.
- Section X describes Administrative costs and Research and Development activities.
- Section XI documents the 2023 EECRF.
- Section XII documents the 2022 EECRF Summary.
- Section XIII documents the Underserved Counties.

Acronyms

- A list of abbreviations for common terms used within this document.

Appendices

- Appendix A – Reported and verified demand and energy reductions by county for each program.
- Appendix B – Program templates for any new or significantly modified programs and programs not included in the previous EEPR.
- Appendix C – Data, explanations, or documents supporting other sections of the EEPR.

EXECUTIVE SUMMARY – ENERGY EFFICIENCY PLAN (PLAN)

AEP Texas plans to achieve its 2023 mandated demand and energy goals of 21.08 MW and 36,932 MWh as shown in Table 1 below through residential and non-residential SOPs and MTPs. AEP Texas will utilize a budget of $18,797,166 to accomplish these goals.

Table 1: Summary of Goals, Projected Savings (at the Meter), and Budgets [1]

Calendar Year	Average Peak Demand at Meter (MW)	Goal Metric: 0.4% Peak Demand (MW)	Peak Demand Goal (MW)	Energy Goal (MWh)	Projected Demand Reduction (MW)	Projected Energy Savings (MWh)	Projected Budget (000's)*
2023	5,271	21.08	21.08	36,932	61	76,648	$18,797
2024	5,387	21.55	21.55	37,756	61	76,758	$18,928

* The Projected Budgets include costs associated with Evaluation, Measurement & Verification activities.

EXECUTIVE SUMMARY – ENERGY EFFICIENCY REPORT (REPORT)

AEP Texas achieved demand and energy reductions of 53,404 kW and 83,915,065 kWh in 2022. The total energy efficiency cost for achieving these savings was $17,220,700 This achievement exceeded the 2022 mandated energy efficiency goals of 20,830 kW and 36,494,000 kWh.

A broad portfolio of residential and non-residential SOPs and MTPs was used to accomplish these savings.

[1] Average Peak Demand figures are from Table 4. Projected Savings from Table 5; Projected Budgets from Tables 6 and 7

ENERGY EFFICIENCY PLAN

I. 2023 Programs

A. 2023 Program Portfolio

AEP Texas has implemented a variety of programs in 2023 to enable it to meet its goals in a manner that complies with PURA § 39.905 and the EE Rule. These programs target broad market segments and specific market sub-segments with significant opportunities for cost-effective energy savings.

Table 2 summarizes the programs and targeted customer class markets for Program Year 2023. The programs listed in Table 2 are described in further detail in Subsection B. AEP Texas maintains a website containing information on participation, forms required for project submission, and program manuals at www.AEPTexasEfficiency.com. This site is the primary method of communication used to provide program updates and information to Retail Electric Providers (REPs), potential Energy Efficiency Service Providers (EESPs), and other interested parties.

Implementation Process

MTPs are implemented by third-party implementers. These implementers design, market and execute the applicable MTPs. Based on the specific MTP, the implementer may perform outreach activities to recruit local contractors and provide participating contractors specialized education, training/certification and tools as necessary. Implementers validate proposed measures/projects, perform quality assurance/quality control, and verify and report savings derived from the program.

SOPs are managed in-house with project sponsors providing eligible program measures. Project sponsors are typically EESPs; however, for commercial projects an AEP Texas end-use customer may serve as its own project sponsor. Eligible project sponsors can submit an application(s) for project(s) meeting the minimum SOP requirements.

AEP Texas monitors projects being submitted so as to not accept duplicate enrollments for the same measures in multiple programs.

Outreach Activities

- Promote internet websites with program information including project eligibility, end-use measures, incentives, procedures, application forms, and in some cases a list of participating project sponsors and the available program budget;
- Utilize mass e-mail notifications to inform and update potential project sponsors on AEP Texas energy efficiency program opportunities;
- Conduct workshops as necessary to explain program elements such as responsibilities of the project participants, program requirements, incentive information and the application and reporting process;
- Conduct specific project sponsor/contractor training sessions as necessary based on the energy efficiency programs being implemented;
- Participate in local, regional, state-wide, and industry-related outreach activities as may be necessary; and
- Facilitate earned media opportunities, spotlighting successful projects and/or interesting stories as applicable.

Table 2: 2023 Energy Efficiency Program Portfolio

Program	Target Market	Application
Commercial Foodservice Pilot MTP	Commercial	Retrofit & New Construction
Commercial Solutions MTP	Commercial	Retrofit & New Construction
Commercial SOP	Commercial	Retrofit & New Construction
CoolSaver℠ A/C Tune-Up MTP	Commercial & Residential	Retrofit
Hard-to-Reach SOP	Residential Hard-to-Reach	Retrofit & New Construction
High-Performance New Homes MTP	Residential	New Construction
Load Management SOP	Commercial	Retrofit
Open MTP	Commercial	Retrofit
Residential SOP	Residential	Retrofit & New Construction
SCORE/CitySmart MTP	Commercial	Retrofit & New Construction
SMART Source℠ Solar PV MTP	Commercial & Residential	Retrofit & New Construction
Targeted Low-Income Energy Efficiency Program	Low-Income Residential	Retrofit
Winter Load Management SOP	Commercial	Retrofit

B. Existing Programs

Commercial Solutions Market Transformation Program (CS MTP)

The CS MTP targets commercial customers (other than governmental and educational entities) that do not have the in-house expertise to: 1) identify, evaluate, and undertake energy efficiency improvements; 2) properly evaluate energy efficiency proposals from vendors; and/or 3) understand how to leverage their energy savings to finance projects. Incentives are paid to customers for eligible energy efficiency measures that are installed in new or retrofit applications that result in verifiable demand and energy savings.

Commercial Standard Offer Program (CSOP)

The CSOP targets commercial customers of all sizes. Variable incentives are available to project sponsors based upon verified demand and energy savings for eligible measures installed in new or retrofit applications.

CoolSaver A/C Tune-Up Market Transformation Program (CoolSaver MTP)

The CoolSaver MTP is designed to overcome market barriers that prevent residential and small commercial customers from receiving high performance air conditioning (A/C) system tune-ups. The program works through local A/C networks to offer key program components, including:

- Training and certifying A/C technicians on the tune-up and air flow correction services and protocols.
- Paying incentives to A/C contactors for the successful implementation of A/C tune-up and air flow correction services.
- Paying incentives to A/C contractors who replace existing residential air conditioners and/or heat pumps with new high efficiency units of 16 SEER or higher. Additional incentives are paid for early retirement of operational equipment and for "right-sizing" replacement units.

Hard-to-Reach Standard Offer Program (HTR SOP)

The HTR SOP targets residential customers with total annual household incomes at or below 200% of current federal poverty guidelines. Incentives are paid to project sponsors for eligible measures installed in new and retrofit applications that result in verifiable demand and energy savings. Project comprehensiveness is encouraged and customer education materials regarding energy conservation behavior are distributed by project sponsors.

High-Performance New Homes Market Transformation Program (New Homes MTP)

The New Homes MTP targets several market participants, primarily homebuilders and consumers. The program's goal is to create conditions in which consumers demand energy-efficient homes, and homebuilders supply them. Incentives are paid to homebuilders who construct homes to strict energy-efficient building guidelines and that are at least 5% above the Texas Baseline Reference Home and meet all minimum energy code requirements. The program has a tiered design that uses a combination of mandatory, additional elective, and innovative measures to promote market transformation and drive deep energy savings. ENERGY STAR® and complete foam encapsulated homes are offered as alternative pathways to Tiers. Bonus incentives are offered for heat pump water heaters, Level 2 ENERGY STAR EV chargers, ENERGY STAR smart thermostats, affordable/low-income housing, right-sized HVAC and to builders who switch from electric resistance furnaces to heat pumps. Each home results in verifiable demand and energy savings. In addition to homebuilder and consumer outreach, the New Homes MTP targets key market actors in the homebuilding production and sales cycle: home energy raters, homebuilder sales agents, real estate agents, HVAC contractors, mortgage lenders, product manufacturers, homebuilder associations, and media outlets.

Load Management Standard Offer Program (LM SOP)

The LM SOP targets non-residential customers with a peak electric demand of 500 kW or more and able to reduce at least 5 kW demand or more during a curtailment event. Curtailment events occur during the program operating period June 1, 2022 through September 30, 2022, from 1 pm through 7 pm excluding weekends and federal holidays. Program participants include non-residential customers and Market Actors that include national or local energy efficiency service providers, commercial aggregation groups and retail electric providers (REPS). Load curtailment events are dispatched by AEP Texas to the program participants providing a 30-minute advance notification and will have a one-to-four-hour duration. Incentive payments are based on the average measured and verified demand reduction during the program operating period.

Open Market Transformation Program (Open MTP)

The Open MTP targets traditionally underserved small commercial customers who may not employ knowledgeable personnel with a focus on energy efficiency, who are limited in the ability to implement energy efficiency measures, and/or who typically do not actively seek the help of a professional EESP. Small commercial customers with a peak demand not exceeding 150 kW in the previous twelve consecutive billing months may qualify to participate in the program. Available incentives are paid directly to the contractor, thereby reducing a portion of the project cost for the customer.

The program is intended to overcome market barriers for participating contractors by providing technical support and incentives to implement energy efficiency upgrades and produce demand and energy savings.

Residential Standard Offer Program (RSOP)

The RSOP targets all residential customers, paying incentives to project sponsors for eligible measures installed in new and retrofit applications that result in verified demand and energy savings. Project comprehensiveness is encouraged.

SCORE/CitySmart Market Transformation Program (SCORE/CS MTP)

The SCORE/CS MTP provides energy efficiency and demand reduction solutions for public and private educational entities grades K-12 as well as colleges and universities. In addition to educational facilities, SCORE/CS MTP provides these same solutions to local, state, county and federal government customers. This program is designed to help educate and assist these customers in lowering their energy use by facilitating the integration of energy efficiency into their short- and long-term planning, budgeting, and operational practices. Incentives are paid to participating customers for eligible energy efficiency measures that are installed in new or retrofit applications that result in verifiable demand and energy savings.

SMART Source℠ Solar PV Market Transformation Program (PV MTP)

The PV MTP offers incentives to residential and commercial customers for the installation of solar photovoltaic (PV) systems interconnected on the customer's side of the meter. The incentives help offset the initial costs of installing solar PV systems, and encourage service providers to seek more installation opportunities. In addition to demand and energy savings achieved from the installations, the PV MTP aims to transform the solar PV market by increasing the number of qualified technicians and installers and decreasing the average installed cost of PV systems, thereby creating greater market economies of scale.

Targeted Low-Income Energy Efficiency Program (TLIP)

The TLIP is designed to cost-effectively reduce the energy consumption and energy costs for low-income residential customers in the AEP Texas service territory. Weatherization service providers install eligible weatherization and energy efficiency measures in qualified households that meet the Department of Energy (DOE) income-eligibility guidelines of at or below 200% of the federal poverty guidelines. A Savings-to-Investment Ratio of 1.0 or higher is required of each serviced dwelling unit.

C. New Programs for 2023

Winter Load Management SOP (WLM SOP)

The WLM SOP targets non-residential customers with a peak electric demand of 500 kW or more and able to reduce at least 100 kW demand or more during a curtailment event. Curtailment events occur during the winter program operating period December 1 through February 28, 24 hours a day, seven days a week. Program participants include non-residential customers and Market Actors that include national or local energy efficiency service providers, commercial aggregation groups and retail electric providers (REPS). Load curtailment events are dispatched by AEP Texas to the program participants providing a 30-minute advance notification and will have a one-to-four-hour duration. Incentive payments are based on the average measured and verified demand reduction during the program operating period.

Foodservice Pilot Market Transformation Program (Foodservice MTP)

The Foodservice MTP targets commercial foodservice participants and market actors. This program will feature a point-of-sale rebate at the foodservice equipment dealer and will engage other key market actors to stimulate the adoption of energy efficient equipment.

D. Discontinued Programs

There are no discontinued programs for 2023.

II. Customer Classes

The AEP Texas energy efficiency programs target its Residential and Commercial customer classes. The programs also target customer sub-classes, such as Residential Hard-to-Reach and Low-Income, Schools, Small Businesses, and Local Governments.

The annual projected savings targets are allocated among these customer classes and sub-classes by examining historical program results and by evaluating economic trends, in compliance with 16 TAC § 25.181(e)(3).

Table 3 summarizes the number of customers in each customer class and the Residential Hard-to-Reach sub-class. The numbers listed are the actual number of active electric service accounts by class served for the month of January 2023. These numbers were used to determine goal and budget allocations for each customer class and program. It should be noted, however, that the actual distribution of the annual goal and budget required to achieve the goal must remain flexible based upon the conditions of the marketplace, the potential interest a customer class may have in a specific program, and the overriding objective of meeting the mandated demand and energy reduction goals in total. AEP Texas offers a varied portfolio of SOPs and MTPs such that all eligible customer classes have access to energy efficiency alternatives.

Table 3: Summary of Customer Classes

Customer Class	Number of Customers
Commercial	206,642
Residential	990,736
Hard-to-Reach [2]	311,091

* Hard-to-Reach customer count is a sub-set of the Residential total

[2] According to the U.S. Census Bureau's 2021 Current Population Survey, 31.4% of Texas families fell below 200% of the poverty threshold in 2020. Applying that percentage to AEP Texas' residential customer base of 990,736, the number of HTR customers is estimated to be 311,091.

III. Energy Efficiency Goals and Projected Savings

AEP Texas' 2023 annual demand and energy reduction goals to be achieved are 21.08 MW and 36,932 MWh. AEP Texas' 2024 annual goals are 21.55 MW and 37,756 MWh. These goals have been calculated as prescribed by the EE Rule.

The 2023 goal was calculated by applying four-tenths of 1% (0.004) of the summer weather-adjusted peak demand for its residential and commercial customers to the five year average (2017-2021) peak demand at the meter of 5,271 MW. This resulted in a calculated goal of 21.08 MW.

The 2024 demand goal is calculated by applying four-tenths of 1% (0.004) of the summer weather-adjusted peak demand for its residential and commercial customers to the five year average (2018-2022) peak demand at the meter of 5,387 MW. This results in a calculated goal of 21.55 MW.
As stated in 16 TAC § 25.181(e)(4), a utility's energy savings goal is calculated from its demand savings goal, using a 20% conservation load factor.

Table 4 presents historical annual growth in demand data for the previous five years that was used to calculate AEP Texas' goals. Table 5 presents the projected demand and energy savings for Program Years 2023 and 2024 by program, for each customer class with fully-deployed program budgets.

Table 4: Annual Growth in Demand and Energy Consumption – AEP Texas

Calendar Year	Peak Demand (MW) @ Source						Energy Consumption (GWh) @ Meter				Energy Efficiency Goal Calculations		
	Total System		Residential & Commercial				Total System		Residential & Commercial				
	Actual	Weather Adjusted	Actual	Weather Adjusted	Opt-Out	Peak Demand at Source Net Opt-outs	Actual	Weather Adjusted	Actual	Weather Adjusted	Peak Demand at Meter*	5 year Average Peak Demand at Meter	Goal Metric: 0.4% Peak Demand at Meter
2016	6.412	6,270	5.910	5.768	-75	5,693	31.604	31.224	25,791	25.411	5,134	NA	NA
2017	6,391	6.234	5,879	5,722	-101	5,621	31,553	31,334	25.072	24,853	5.069	NA	NA
2018	6.339	6,349	5.817	5.827	-109	5,718	32.020	31.680	25,693	25.353	5,265	5.002	NA
2019	6.501	6,364	5.945	5.807	-106	5,701	31.962	31.564	25,675	25.277	5,248	5.043	NA
2020	6,451	6.417	5,875	5,841	-75	5.766	31,746	31,767	25.194	25,214	5.317	5,112	NA
2021	6.451	6,580	5.814	5.943	-25	5,918	32.975	33.004	26,253	26.282	5,457	5.152	NA
2022	6.915	6,842	6.244	6.170	-47	6,123	35.714	35.500	28,877	28.663	5,647	5.207	NA
2023	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	5,271	21 08
2024	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	5.387	21 55

*Line losses are derived from the loss factors determined in the most recent line loss studies for AEP Texas (Central Division and North Division).

Table 5: Projected Demand and Energy Savings by Program for Each Customer Class for 2023 and 2024 (at the Meter) – AEP Texas

Customer Class and Program	Projected Savings 2023		Projected Savings 2024	
	kW	kWh	kW	kWh
Commercial	**51,311**	**46,424,144**	**51,327**	**46,534,287**
Commercial Foodservice Pilot MTP	25	166,479	41	276,622
Commercial Solutions MTP	1,664	7,458,262	1,664	7,458,262
Commercial SOP	3,133	16,316,286	3,133	16,316,286
CoolSaver^{SM} A/C Tune-Up MTP	3,466	8,047,475	3,466	8,047,475
Load Management SOP	26,308	26,308	26,308	26,308
Open MTP	1,215	5,234,159	1,215	5,234,159
SCORE/CitySmart MTP	2,463	8,259,385	2,463	8,259,385
SMART Source^{SM} Solar PV MTP	269	903,022	269	903,022
Winter Load Management SOP	12,768	12,768	12,768	12,768
Residential	**7,353**	**23,625,695**	**7,353**	**23,625,695**
CoolSaver^{SM} A/C Tune-Up MTP	1,594	6,250,000	1,594	6,250,000
High-Performance New Homes MTP	2,215	3,703,316	2,215	3,703,316
Residential SOP	2,785	11,187,718	2,785	11,187,718
SMART Source^{SM} Solar PV MTP	759	2,484,661	759	2,484,661
Hard-to-Reach	**2,248**	**6,597,665**	**2,248**	**6,597,665**
Hard-to-Reach SOP	1,408	5,065,232	1,408	5,065,232
TLI EE Program	840	1,532,434	840	1,532,434
Total Annual Projected Savings	**60,913**	**76,647,505**	**60,929**	**76,757,648**

IV. Program Budgets

Tables 6 and 7 present total proposed budget allocations required to meet AEP Texas' projected demand and energy savings to be achieved for Program Year 2023 and 2024. The budget allocations are defined by the overall projected demand and energy savings, the avoided costs of capacity and energy specified in the EE Rule, allocation of demand goals, and the incentive levels by customer class. The budget allocations are detailed by customer class, program, and in the following budget categories: incentives, administration, research and development (R&D), and evaluation, measurement and verification (EM&V).

Table 6: Projected Annual Budget by Program for Each Customer Class for 2023 AEP Texas

2023	Incentives	Admin	R&D	EM&V	Total Budget
Commercial					
Commercial Foodservice Pilot MTP	$250,000	$25,000			$275,000
Commercial Solutions MTP	$903,248	$111,255			$1,014,503
Commercial SOP	$1,875,762	$218,467			$2,094,229
CoolSaver℠ A/C Tune-Up MTP	$796,700	$79,393			$876,093
Load Management SOP	$737,700	$83,863			$821,563
Open MTP	$1,213,041	$147,253			$1,360,294
SCORE/CitySmart MTP	$1,192,300	$125,165			$1,317,465
SMART Source℠ Solar PV MTP	$287,310	$32,375			$319,685
Winter Load Management SOP	$350,000	$25,000			$375,000
Residential					
CoolSaver℠ A/C Tune-Up MTP	$825,000	$80,578			$905,578
High-Performance New Homes MTP	$965,000	$107,222			$1,072,222
Residential SOP	$3,164,657	$330,499			$3,495,156
SMART Source℠ Solar PV MTP	$670,941	$70,434			$741,375
Hard-to-Reach					
Hard-to-Reach SOP	$1,412,560	$143,787			$1,556,347
Targeted Low-Income Energy Efficiency Program	$1,799,159	$187,144			$1,986,303
Research and Development					
R&D			$353,646		$353,646
Evaluation, Measurement & Verification (EM&V)					
EM&V				$232,708	$232,708
Total Budget	**$16,443,378**	**$1,767,434**	**$353,646**	**$232,708**	**$18,797,166**

Table 7: Projected Annual Budget by Program for Each Customer Class for 2024 AEP Texas

2024	Incentives	Admin	R&D	EM&V	Total Budget
Commercial					
Commercial Foodservice Pilot MTP	$280,000	$25,000			$305,000
Commercial Solutions MTP	$903,248	$115,485			$1,018,733
Commercial SOP	$1,875,762	$218,467			$2,094,229
CoolSaver℠ A/C Tune-Up MTP	$796,700	$88,522			$885,222
Load Management SOP	$737,700	$85,300			$823,000
Open MTP	$1,213,041	$150,959			$1,364,000
SCORE/CitySmart MTP	$1,192,300	$141,884			$1,334,184
SMART Source℠ Solar PV MTP	$287,310	$35,017			$322,327
Winter Load Management SOP	$350,000	$25,000			$375,000
Residential					
CoolSaver℠ A/C Tune-Up MTP	$825,000	$91,667			$916,667
High-Performance New Homes MTP	$965,000	$107,222			$1,072,222
Residential SOP	$3,164,657	$359,868			$3,524,525
SMART Source℠ Solar PV MTP	$670,941	$79,059			$750,000
Hard-to-Reach					
Hard-to-Reach SOP	$1,412,560	$156,840			$1,569,400
Targeted Low-Income Energy Efficiency Program	$1,799,159	$187,144			$1,986,303
Research and Development					
R&D			$353,646		$353,646
Evaluation, Measurement & Verification (EM&V)					
EM&V				$233,450	$233,450
Total Budget	**$16,473,378**	**$1,867,434**	**$353,646**	**$233,450**	**$18,927,908**

ENERGY EFFICIENCY REPORT

V. Historical Demand and Energy Goals and Savings Achieved for the Previous Five Years

Table 8 contains the demand and energy reduction goals and actual savings achieved for the previous five years (2018-2022) calculated in accordance with the EE Rule.

Table 8: Historical Demand and Energy Goals* and Savings Achieved (at the Meter)

Calendar Year	Actual Weather Adjusted Demand Goal (MW)	Actual Weather Adjusted Energy Goal (MWh)	Savings Achieved (MW)	Savings Achieved (MWh)
AEP Texas				
2022	20.83	36,494	53.4**	83,915
2021	20.60	36,091	45.31	83,701
Central				
2020	16.38	28,698	50.45	59,259
2019	16.14	28,277	39.70	58,398
2018	15.99	28,014	43.81	62,417
North				
2020	4.26	7,464	5.79	12,768
2019	4.26	7,464	6.58	11,968
2018	4.26	7,464	8.95	12,669

* Actual Weather Adjusted MW and MWh Goals as reported in the EEPRs filed in years 2018-2022.
**Central and North divisions are combined. Reported savings achieved at the source are 48.12 MW (48.12 x 1/(1-7.284%)) = 51.9 MW for Central division and 5.29 MW (5.29 x 1/(1-9.957%)) = 5.87 MW for North division.

VI. Projected, Reported and Verified Demand and Energy Savings

Table 9: Projected versus Reported and Verified Savings for 2022 and 2021 (at the Meter)

2022	Projected Savings		Reported and Verified Savings	
Customer Class and Program	kW	kWh	kW	kWh
Commercial				
Commercial Solutions MTP	1,664	7,458,262	1,649	7,980,776
Commercial SOP	2,554	13,452,356	3,131	15,955,810
CoolSaver℠ A/C Tune-Up MTP	3,466	8,047,475	5,711	11,685,066
Load Management SOP	26,507	24,387	28,968	28,968
Open MTP	1,215	5,234,159	1,252	4,529,866
SCORE/City Smart MTP	2,463	8,259,385	2,437	9,927,928
SMART Source℠ Solar PV MTP	278	901,737	320	1,010,922
Residential				
CoolSaver℠ A/C Tune-Up MTP	1,594	6,250,000	1,522	7,753,843
High-Performance New Homes MTP	2,353	3,917,476	2,657	4,578,039
Residential SOP	2,191	9,477,974	2,720	10,761,775
SMART Source℠ Solar PV MTP	615	2,101,421	897	3,223,034
Hard-to-Reach				
Hard-to-Reach SOP	1,930	3,845,156	1,470	5,247,286
TLI EE Program	966	1,517,843	671	1,231,753
Total Annual Savings	**47,797**	**70,487,631**	**53,404**	**83,915,065**
2021	**Projected Savings**		**Reported and Verified Savings**	
Customer Class and Program	kW	kWh	kW	kWh
Commercial				
Commercial Solutions MTP	1,433	8,709,280	1,650	7,631,163
Commercial SOP	3,067	13,639,318	3,184	18,413,777
CoolSaver℠ A/C Tune-Up MTP	1,393	4,376,124	4,497	9,015,723
Load Management SOP	22,261	20,480	21,647	21,647
Open MTP	1,184	4,660,806	1,216	5,117,184
SCORE/City Smart MTP	2,061	9,680,000	2,284	9,645,175
SMART Source℠ Solar PV MTP	380	1,187,409	237	862,214
Residential				
CoolSaver℠ A/C Tune-Up MTP	1,017	3,223,609	1,299	6,540,544
High-Performance New Homes MTP	3,394	4,366,339	2,266	3,248,011
Residential Pool Pump Pilot MTP	2,134	3,520,650	2,963	14,095,317
Residential SOP	173	1,203,872	14	180,186
SMART Source℠ Solar PV MTP	301	925,735	468	1,602,578
Hard-to-Reach				
Hard-to-Reach SOP	1,551	2,418,835	2,277	4,931,719
Targeted Low-Income Energy Efficiency Program	917	1,392,896	1,309	2,395,875
Total Annual Savings	**41,267**	**59,325,352**	**45,311**	**83,701,112**

VII. Historical Program Expenditures

This section documents AEP Texas' incentive and administration expenditures for the previous five years (2018-2022) detailed by program for each customer class.

Table 10: Historical Program Incentive and Administrative Expenditures for 2018 through 2022 (000's) – AEP Texas

	2022		2021		2020		2019		2018	
	Incent.	**Admin**	**Incent.**	**Admin**	**Incent.**	**Admin**	**Incent.**	**Admin**	**Incent.**	**Admin**
Commercial										
Commercial Solutions MTP	$876 53	$83.80	$900.63	$103.88	$869.07	$97 15	$900 31	$107.09	$946.24	$89.56
Commercial SOP	$1,846 07	$235.99	$2,000.12	$230.86	$1,798.52	$216 04	$1,974.48	$232 53	$2,143 87	$247.80
CoolSaver℠ A/C Tune-Up MTP	$876 77	$61.63	$595.48	$49.88	$595.50	$49.42	$647.82	$53.34	$604.06	$45.81
Load Management SOP	$802.17	$90.38	$573 38	$64.45	$828.41	$61 74	$584 63	$50.03	$689 19	$86.07
Open MTP	$1,055.08	$111.85	$1,199.15	$124.51	$1,205.48	$134.37	$1,195.60	$144.59	$1,211.80	$108.26
SCORE/CitySmart MTP	$1,180.23	$112 44	$1,127.97	$110.45	$1,121.97	$106.35	$1,111 64	$113.42	$1,075.94	$108.22
SMART Source℠ Solar PV MTP	$169.78	$17.76	$197.02	$19.66	$254.47	$27.80	$284.99	$22.66	$274.76	$20.29

(Table continued on next page)

Table 10: Historical Program Incentive and Administrative Expenditures for 2018 through 2022 (000's) – AEP Texas (Continued)

	2022		2021		2020		2019		2018	
	Incent.	**Admin**	**Incent.**	**Admin**	**Incent.**	**Admin**	**Incent.**	**Admin**	**Incent.**	**Admin**
Residential										
CoolSaver[SM] A/C Tune-Up MTP	$819.78	$74.64	$677.93	$56.78	$673.00	$55.85	$696.41	$57.31	$667.18	$50.61
High-Performance New Homes MTP	$844.09	$97.17	$947.26	$90.06	$909.56	$78.92	$807.36	$73.92	$750.25	$88.73
Residential Pool Pump Pilot MTP	NAP	NAP	$73.66	$10.88	$65.90	$13.11	$76.70	$9.68	NAP	NAP
Residential SOP	$2,963.58	$279.89	$3,365.28	$329.41	$3,445.80	$326.30	$3,260.74	$363.80	$3,284.20	$355.40
SMART Source[SM] Solar PV MTP	$605.92	$59.87	$307.75	$32.77	$293.18	$31.04	$300.25	$24.11	$316.97	$23.23
Hard-to-Reach										
Hard-to-Reach SOP	$1,427.56	$135.03	$1,412.44	$176.68	$1,624.91	$175.96	$1,453.44	$127.71	$1,456.26	$160.66
Targeted Low-Income Energy Efficiency Program	$1,611.58	$178.63	$1,826.49	$173.45	$1,771.13	$142.18	$1,813.52	$183.16	$1,596.78	$141.97
Research and Development (R&D)	NAP	$391.13	NAP	$177.82	NAP	$280.10	NAP	$386.96	NAP	$235.76
Evaluation and Measurement Verification (EM&V)	NAP	$211.36	NAP	$206.95	NAP	$215.60	NAP	$211.99	NAP	$208.09
Total Expenditures	**$15,079.13**	**$2,141.57**	**$15,204.57**	**$1,958.49**	**$15,456.90**	**$2,011.93**	**$15,107.89**	**$2,162.30**	**$15,017.50**	**$1,970.46**

VIII. Program Funding for Program Year 2022

As shown in Table 11 the total projected budget for AEP Texas in 2022 was $17,959,017 and the actual total funds expended were $17,220,700. This is an overall total program expenditure difference of 4% from the amount budgeted.

The following individual program expenditures differed from their respective proposed budgets by more than 10%, as explained below.

The Open Market Transformation Program was under budget by more than 10% because there were new contractors in the program (which takes more time for education and startup), which resulted in fewer program participants and completed projects. Additionally, customers cancelled projects due to budget constraints, and contractors had issues with product shipment delays.

The High Performance New Homes MTP was under budget due to various reasons including a decrease in building permits/starts and the adjustment of incentive funding to higher performing measures, some of which inventory was not readily available.

The SMART Source^{SM} Solar PV MTP commercial class was under budget due to a large project being delayed by supply chain issues.

The SMART Source^{SM} Solar PV MTP residential class was under budget due to a smaller volume of projects participating in the program. (due to delays in installers completing interconnection documentation.)

The combined 2022 expenditures for the TLIP and the HTR SOP constituted 18.9% of the energy efficiency budget.

Table 11: Program Funding for Program Year 2022– AEP Texas

	Total Projected Budget [3]	Numbers of Customers Participating	Actual Funds Expended (Incentives)	Actual Funds Expended (Admin)	Research and Development (R&D)	Evaluation and Measurement Verification (EM&V)	Total Funds Expended
Commercial							
Commercial Solutions MTP	$1,018,733	154	$876,527	$83,799			$960,326
Commercial SOP	$2,094,229	97	$1,846,073	$235,986			$2,082,059
CoolSaver℠ A/C Tune-Up MTP	$885,222	853	$876,772	$61,632			$938,403
Load Management SOP	$823,000	292	$802,171	$90,376			$892,547
Open MTP	$1,364,000	148	$1,055,076	$111,849			$1,166,925
SCORE/CitySmart MTP	$1,334,184	109	$1,180,225	$112,441			$1,292,666
SMART Source℠ Solar PV MTP	$322,327	6	$169,780	$17,762			$187,543
Residential							
CoolSaver℠ A/C Tune-Up MTP	$916,667	3,050	$819,778	$74,643			$894,421
High-Performance New Homes MTP	$1,072,222	961	$844,092	$97,174			$941,266
Residential SOP	$3,257,725	3,294	$2,963,580	$279,887			$3,243,467
SMART Source℠ Solar PV MTP	$750,000	178	$605,919	$59,872			$665,791
Hard-to-Reach							
Hard-to-Reach SOP	$1,569,400	1,831	$1,427,558	$135,030			$1,562,587
Targeted Low-Income Energy Efficiency	$1,986,303	388	$1,611,583	$178,626			$1,790,209
Research and Development	$353,646				$391,130		$391,130
EM&V							
Statewide EM&V Contractor	$211,359					$211,359	$211,359
Total	**$17,959,017**	**11,361**	**$15,079,133**	**$1,539,077**	**$391,130**	**$211,359**	**$17,220,700**

[3] Projected Budget from the revised EEPR filed May 2022 Project No. 53679

IX. Market Transformation Program Results 2022

Commercial Solutions MTP

The Commercial Solutions MTP goal was to acquire 1,644 kW demand savings. A total of 1,649 kW was achieved by participation of 154 customers.

CoolSaver^SM MTP

The CoolSaver^SM MTP verified and reported 7,233 kW. This included participation by 3,903 residential and commercial customers.

High-Performance New Homes MTP (New Homes)

In 2022, 961 high-performance homes were constructed in the New Homes program with a savings of 2,657 kW. Despite the decrease in building permits and home starts, the number of program homes increased as did customers learning about and benefiting from energy efficient homes. The program provided continuing education courses and other training opportunities for contractors, homebuilders, home energy raters, HVAC contractors and other market actors on the advantages of High-Performance and ENERGY STAR homes and building practices. Training for HVAC market actors focused on Manual J training to re-emphasize the importance of performing load calculations for correctly sizing HVAC systems. AEP Texas continued their partnership with the Environmental Protection Agency's (EPA) ENERGY STAR program and received the ENERGY STAR Partner of the Year Sustained Excellence award.

Open MTP

The Open MTP goal was to acquire 1,215 kW demand savings. A total of 1,252 kW was achieved with 148 small commercial customers and 17 participating contractors.

SCORE/CitySmart MTP

The SCORE/CitySmart MTP was projected to acquire 2,463 kW demand savings A total of 2,437 kW was achieved. This included participation by 109 customers.

SMART Source^SM Solar PV MTP

The PV MTP projected to acquire 893 kW in demand savings and 3,003,158 kWh in energy savings from the residential and non-residential components. A total of 184 residential and non-residential solar PV projects were completed within the program, resulting in a peak demand reduction of 1,217 kW and 4,233,956 kWh of energy savings.

X. Administrative Costs and Research and Development

Administrative Costs

Administrative costs incurred to meet the energy efficiency goals and objectives include, but may not be limited to, energy efficiency employees' payroll, costs associated with regulatory filings, and EM&V costs outside of the actual cost associated with the EM&V contractor. Any portion of these costs that are not directly assignable to a specific program are allocated among the programs in proportion to the program incentive costs.

Program Research and Development

R&D activities are intended to help AEP Texas meet future energy efficiency goals by researching new technologies and program options and developing better, more efficient ways to administer current programs. In 2022 AEP Texas dedicated resources to enhance data collection and management systems for current programs. In addition, AEP Texas participated with Electric Utility Marketing Managers of Texas (EUMMOT) in researching potentially new deemed savings measures for various programs. AEP Texas provided support to the Texas Energy Poverty Research Institute (TEPRI) to study *Elevating Equity in Residential Solar Deployment*. This study explores the feasibility of distributed solar for low income residential electric customers, particularly in rural areas served by AEP Texas.

Informational Activities

AEP Texas continues its best effort to encourage and facilitate the involvement of REPs and EESPs in the delivery of its programs to customers.

XI. 2023 Energy Efficiency Cost Recovery Factor (EECRF)

AEP Texas' 2023 EECRF was approved by the Commission in Docket No. 53679 and includes $26,029,727 for AEP Texas as shown in Table 12. The adjusted factors are shown in Table 13.

Table 12: 2023 EECRF

2023 Projected Costs	$18,024,458
Performance Bonus for 2021 results	$7,931,405
Over-recovery, returned to customers with interest	($197,105)
EECRF proceeding expenses	$38,262
Projected EM&V costs	$232,708
Total EECRF	$26,029,727

Table 13: 2023 EECRF Factors

Customer Class	AEP Texas
Residential Service	$0.001062 per kWh
Secondary Service (less than or equal to 10 kW)	$0.000852 per kWh
Secondary Service (greater than 10 kW)	$0.000958 per kWh
Primary Service	$0.000446 per kWh
Transmission Service	$0.000000 per kW

XII. 2022 EECRF Summary

2022 Collections for Energy Efficiency

AEP Texas collected $26,462,307 through its 2022 EECRF. A performance bonus of $8,673,275 for exceeding its 2020 energy efficiency goals and $351,084 returned to customers are reflected in the total amount collected for energy efficiency in 2022.

Energy Efficiency Program Costs Expended

AEP Texas expended a total of $17,220,700 for its 2022 energy efficiency programs. The amount expended is $738,317 less than the 2022 projected budget of $17,959,017 for energy efficiency programs.

Over-Recovery of Energy Efficiency Costs

AEP Texas' actual 2022 energy efficiency program costs (including EM&V costs) less municipal rate case expenses are $17,214,162 and actual energy efficiency program revenues are $17,437,948. These associated 2022 costs and revenues result in a total over-recovery of energy efficiency costs of $223,786. Included in that number is a small amount of trailing under-recovery, $451, from the Transmission Class that has continued since base rate energy efficiency recovery existed for that class. AEP Texas has determined to forego the recovery of this small amount. The adjusted PY 2022 over-recovery is $224,236. Including interest of $2,941 the over-recovery is $227,177. This is the amount that the AEP Texas will request be returned to customers within its 2024 EECRF.

XIII. Underserved Counties

AEP Texas has defined Underserved Counties as any county in the service territory for which no demand or energy savings were reported through any of its 2022 SOPs or MTPs. Per 16 TAC § 25.181(l)(2)(U), a list of the Underserved Counties is shown in Table 14:

Table 14: Underserved Counties

Baylor	Briscoe	Brooks	Brown	Caldwell	Childress
Coleman	Collingsworth	Concho	Cottle	Crane	Dickens
Donley	Fisher	Foard	Gillespie	Gonzalez	Guadalupe
Hall	Hardeman	Haskell	Jackson	Karnes	Kenedy
King	Kinney	Mason	McCulloch	McMullen	Motley
Stephens	Throckmorton	Wheeler	Wilbarger	Wilson	

ACRONYMS

COMMISSION	Public Utility Commission of Texas
CSOP	Commercial Standard Offer Program
CS MTP	Commercial Solutions Market Transformation Program
DR	Demand Response
DSM	Demand Side Management
EECRF	Energy Efficiency Cost Recovery Factor
EEPR	Energy Efficiency Plan and Report
EE Rule	Energy Efficiency Rule, 16 TAC §§ 25.181, 25.182 and 25.183
EESP	Energy Efficiency Service Providers
EPA	Environmental Protection Agency
EUMMOT	Electric Utility Marketing Managers of Texas
Foodservice MTP	Foodservice Pilot Market Transformation Program
HTR	Hard-To-Reach
HTR SOP	Hard-to-Reach Standard Offer Program
LM SOP	Load Management Standard Offer Program
MTP	Market Transformation Program
NAP	Not Applicable
New Homes	High-Performance New Home Market Transformation Program
Open MTP	Open Market Transformation Program

ACRONYMS (Continued)

PURA	Public Utility Regulatory Act
PV	Photovoltaic
PV MTP	SMART Source[SM] Solar PV Market Transformation Program
R&D	Research and Development
REP	Retail Electric Provider
RES	Residential
RSOP	Residential Standard Offer Program
SCORE	Schools Conserving Resources
SCORE/CS MTP	SCORE/CitySmart Market Transformation Program
SOP	Standard Offer Program
TDU	Transmission and Distribution Utility
TLIP	Targeted Low-Income Energy Efficiency Program
TRM	Texas Technical Reference Manual
WLM SOP	Winter Load Management Standard Offer Program

APPENDIX A:

REPORTED AND VERIFIED DEMAND AND ENERGY REDUCTION BY COUNTY: AEP TEXAS

Reported and Verified Demand and Energy Reduction by County: AEP Texas														
County	Commercial Solutions MTP		Commercial SOP		CoolSaverSM A/C Tune-Up MTP (Commercial)		CoolSaverSM A/C Tune-Up MTP (Residential)		Hard-to-Reach SOP		High Performance New Homes MTP		Load Management SOP	
	kW	kWh	kW	kWh	kW	kWh	kW	kWh	kW	kWh	kW	kWh	kW	kWh
Aransas	30.94	157,851									80.69	139,882	1.66	1.66
Atascosa	2.39	9,270											1.25	1.25
Bee	26.39	127,690	1.94	2,770							0.92	2,554	0.05	0.05
Brewster	7.83	30,449	66.41	260,092	0.00	0	0.00	0			0.00	0		
Calhoun											10.37	16,944	0.00	0.00
Callahan			22.57	97,617	0.00	0	0.00	0	1.37	2,237	0.00	0		
Cameron	84.69	403,988	273.69	1,756,718	395.39	817,318	103.80	538,705	111.48	692,327	8.38	13,289	4,798.00	4,798.00
Coke	8.71	39,052			0.00	0	0.00	0			0.00	0		
Colorado	5.40	19,297	16.66	41,774									55.44	55.44
Crockett	24.34	127,024			0.00	0	0.00	0			0.00	0		
Dewitt														
Dimmit	1.30	7,215	2.79	10,846									25.35	25.35
Duval									1.99	11,151			0.87	0.87
Eastland	27.61	144,062			0.00	0	0.00	0			0.00	0		
Edwards													3.91	3.91
Frio	13.45	56,079											36.68	36.68
Goliad											0.55	1,595		
Hidalgo	302.33	1,567,090	538.19	2,674,081	4,079.34	8,305,275	438.48	2,175,403	441.10	1,931,435	415.89	681,687	4,862.41	4,862.41
Irion					0.00	0	0.00	0			0.00	0		
Jeff Davis					0.00	0	0.00	0			0.00	0		
Jim Hogg													1.26	1.26
Jim Wells	22.93	119,262	4.11	20,601					0.89	4,444	11.03	18,011	0.00	0.00
Jones					0.00	0	0.00	0			0.00	0		
Kent					0.00	0	0.00	0			0.00	0		
Kimble					0.00	0	0.00	0			0.00	0		
Kleberg	13.80	76,583	2.94	11,439	6.03	6,535	75.30	390,769	4.69	29,797			60.98	60.98
Knox					0.00	0	0.00	0	77.42	102,633	0.00	0		
La Salle													2.64	2.64
Live Oak									1.16	6,662			0.00	0.00
Matagorda			10.48	44,080									1,258.40	1,258.40
Maverick	77.50	243,213					2.08	4,095					10.52	10.52
Medina											0.94	2,080	14.79	14.79
Menard					0.00	0	0.00	0			0.00	0		
Nolan					0.00	0	0.00	0			0.00	0		
Nueces	134.56	635,207	148.38	598,268			364.76	1,893,207	208.39	857,205	1,855.65	3,097,170	2,523.03	2,523.03
Pecos					0.00	0	0.00	0	9.99	17,372	0.00	0		
Presidio					0.00	0	0.00	0			0.00	0		
Reagan					0.00	0	0.00	0			0.00	0		
Real													1.17	1.17
Reeves					0.00	0	0.00	0	2.40	4,326	0.00	0		
Refugio	8.87	41,975									2.04	3,659	0.00	0.00
Runnels	88.89	542,561			0.00	0	0.00	0	2.57	2,469	0.00	0	10.74	10.74
San Patricio	27.17	105,663	913.47	5,872,884					11.27	35,598	119.51	225,651	6,631.73	6,631.73
Schleicher	3.00	13,426			0.00	0	0.00	0			0.00	0		
Shackelford					0.00	0	0.00	0	2.48	4,169	0.00	0		
Starr	15.53	86,136	15.66	60,944			6.97	36,161	232.67	968,356			0.94	0.94
Sterling	0.40	1,775			0.00	0	0.00	0			0.00	0		
Stonewall					0.00	0	0.00	0			0.00	0		
Sutton	1.31	6,330			0.00	0	0.00	0			0.00	0		
Taylor	245.06	1,159,347	543.03	2,010,777	0.00	0	0.00	0	205.01	344,397	0.00	0	1,172.13	1,172.13
Tom Green	208.56	1,015,730	67.51	284,981	0.00	0	0.00	0	146.44	215,287	0.00	0	76.40	76.40
Upton	1.36	6,102			0.00	0	0.00	0	8.89	17,423	0.00	0		
Uvalde	3.59	25,863											93.04	93.04
Val Verde	72.90	257,933											6.74	6.74
Victoria	13.68	53,145	0.62	2,291							8.59	24,221	2,956.18	2,956.18
Webb	155.58	804,693	502.32	2,205,647	1,224.12	2,523,958	492.82	2,524,377			143.19	352,889	3,124.75	3,124.75
Wharton	18.61	96,765											0.00	0.00
Willacy					6.16	31,980	35.75	185,724					1,230.81	1,230.81
Zapata							1.73	5,402					5.91	5.91
Zavala													0.00	0.00

Reported and Verified Demand and Energy Reduction by County: AEP Texas (Continued)

Reported and Verified Demand and Energy Reduction by County: AEP Texas (Continued)														
County	Open MTP		Residential SOP		SCORE/CitySmart MTP		SMART SourceSM Solar PV MTP (Commercial)		SMART SourceSM Solar PV MTP (Residential)		Targeted Low-Income Energy Efficiency Program		Total	
	kW	kWh	kW	kWh	kW	kWh	kW	kWh	kW	kWh	kW	kWh	kW	kWh
Aransas			2.22	9,129									115.51	306,863
Atascosa									4.36	15,488			7.99	24,759
Bee			6.63	17,677									35.93	150,691
Brewster			0.78	649					1.12	3,876	67.62	138,618	143.76	433,685
Calhoun													10 37	16,944
Callahan	2 00	6,327							10.61	28,225			36 55	134,406
Cameron	60 92	245,972	119.79	523,502	172.49	570,939	8 26	21,823	47.25	164,640			6,184 13	5,754,018
Coke													8.71	39,052
Colorado													77.50	61,126
Crockett													24.34	127,024
Dewitt			0.41	2,633									0.41	2,633
Dimmit									3.39	12,488	100 17	190,948	133 00	221,523
Duval			0 48	3,457									3.34	14,609
Eastland													27 61	144,062
Edwards	10.13	36,578											14.04	36,582
Frio													50.13	56,116
Goliad									3.58	12,760			4.13	14,355
Hidalgo	329.90	1,355,228	844.44	4,031,449	459.66	1,739,540	311.71	989,099	244.52	899,008	20.05	56,049	13,288.02	26,410,207
Irion			5.44	10,506					4.82	19,656			10 26	30,162
Jeff Davis									3.14	11,220			3 14	11,220
Jim Hogg			0.58	3,188									1 84	3,189
Jim Wells			1.90	11,293									40.85	173,610
Jones			2.81	2,334							1.28	3,587	4.10	5,922
Kent					33.10	172,076							33.10	172,076
Kimble	4 32	25,724	4.66	8,905									8.98	34,629
Kleberg			3.82	22,854	11 43	84,599							178.99	622,637
Knox			6.62	13,045									84.04	115,678
La Salle											5 17	8,967	7.81	8,969
Live Oak			0.72	3,769									1.87	10,431
Matagorda									8.09	28,185			1,276.97	73,523
Maverick					0.74	5,060			21.85	90,574	7.88	12,691	120.57	355,643
Medina													15.73	2,095
Menard	4.46	18,717											4.46	18,717
Nolan			1 70	3,374									1.70	3,374
Nueces	12.01	50,027	355.74	2,275,432	926.97	3,897,873			68.97	254,387	39.50	103,119	6,637.97	13,664,416
Pecos			14.23	21,595									24.21	38,967
Presidio									3.15	11,079	0.78	3,867	3.93	14,947
Reagan			7.14	13,239									7.14	13,239
Real	0.00	0	0 00	0	0.00	0	0 00	0	0.00	0	0 00	0	1 17	1
Reeves			3.33	4,297					5.64	19,294			11.38	27,917
Refugio			2 71	9,955									13.62	55,589
Runnels	1.10	4,481	8.00	15,151					4.65	13,198			115.94	577,871
San Patricio	15.59	65,546	27.75	140,271	11.32	62,790							7,757.81	6,515,035
Schleicher													3.00	13,426
Shackelford			6.39	12,990					4.91	15,258			13.77	32,416
Starr			396.89	1,948,390					10.95	43,736	2 39	4,678	681 99	3,148,401
Sterling			4.66	8,155									5.06	9,930
Stonewall											7 67	21,909	7.67	21,909
Sutton	3.86	16,268			71.66	459,353							76.83	481,951
Taylor	179.87	470,391	564.83	1,086,797	368.22	1,677,573			198.91	692,896	55.37	107,823	3,532.43	7,551,172
Tom Green	187.28	320,728	320.44	543,660	14.17	69,638			59.98	208,164			1,080.78	2,658,265
Upton			1.97	3,633									12 22	27,159
Uvalde					34 64	183,268			20.56	60,528	12 54	24,491	164 36	294,243
Val Verde									3.64	22,145	257 80	414,744	341 08	694,829
Victoria									3.71	13,263			2,982.78	95,876
Webb	440.60	1,913,879			179.51	528,240			155.23	570,429	90.27	136,896	6,508.39	11,564,132
Wharton													18.61	96,765
Willacy			3.08	10,445	153.18	476,979							1,428.98	706,359
Zapata													7.64	5,408
Zavala									4.10	12,537	2 75	3,366	6.35	15,903

APPENDIX B:

PROGRAM TEMPLATES

AEP Texas does not have any Program Templates to report this year.

APPENDIX C:
OPTIONAL SUPPORTING DOCUMENTATION

The following files are not convertible:

AEP Texas 2024 EECRF Sch A-B-J-K-M-N-O-P-R Final 05302023.xlsx
AEP Texas EE Identification Notice 2023 Final 05252023.xlsx
AEP Texas Performance Bonus Calculator PY2022.xlsx
AEP TX Schedule A Page 2.xlsx
AEP TX 2023 EEPR Tables v16 (EECRF Filing).xlsx
AEP TX 2023 Sch C-E-G-H-I-Q-WPA-WPC-WPE-WPG WPH 2024.xlsx
AEP TX Schedule B Page 2.xlsx
Central Division Sch C WP.xlsx
North Division Sch C WP.xlsx

Please see the ZIP file for this Filing on the PUC Interchange in order to access these files.

Contact centralrecords@puc.texas.gov if you have any questions.

AEP - TEXAS CENTRAL COMPANY

2017 Analysis of System Losses

January 2019

Final

Prepared by:

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MANAGEMENT APPLICATIONS CONSULTING, INC.

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January 10, 2019

Mr. David M. Roush
Director Regulatory Pricing & Analysis
American Electric Power
1 Riverside Plaza
Columbus, OH 43215

Mr. Chad Burnett
Director Economic Forecasting
American Electric Power
212 East 6th Street
Tulsa, OK 74119

RE: 2017 LOSS ANALYSIS – TCC

Dear Messrs. Roush and Burnett:

Transmitted herewith are the results of the 2017 Analysis of System Losses for the AEP - Texas Central Company's (TCC) power system. Our analysis develops cumulative expansion factors (loss factors) for both demand (peak/kW) and energy (average/kWh) losses by discrete voltage levels applicable to metered sales data. Our analysis considers only technical losses in arriving at our final recommendations.

On behalf of MAC, we appreciate the opportunity to assist you in performing the loss analysis contained herein. The level of detailed load research and sales data by voltage level, coupled with a summary of power flow data and power system model, forms the foundation for determining reasonable and representative power losses on the TCC system. Our review of these data and calculated loss results support the proposed loss factors as presented herein for your use in various cost of service, rate studies, and demand analyses.

Should you require any additional information, please let us know at your earliest convenience.

Sincerely,

Paul M. Normand
Principal

Enclosure
PMN/rjp

AEP - Texas Central Company
2017 Analysis of System Losses

TABLE OF CONTENTS

AEP - Texas Central Company
2017 Analysis of System Losses

1.0 EXECUTIVE SUMMARY

This report presents AEP - Texas Central Company's (TCC) 2017 Analysis of System Losses for the power systems as performed by Management Applications Consulting, Inc. (MAC). The study developed separate demand (kW) and energy (kWh) loss factors for each voltage level of service in the power system for TCC. The cumulative loss factor results by voltage level, as presented herein, can be used to adjust metered kW and kWh sales data for losses in performing cost of service studies, determining voltage discounts, and other analyses which may require a loss adjustment.

The procedures used in the overall loss study were similar to prior studies and emphasized the use of "in house" resources where possible. To this end, extensive use was made of the Company's peak hour power flow data and transformer plant investments in the model. In addition, measured and estimated load data provided a means of calculating reasonable estimates of losses by using a "top-down" and "bottom-up" procedure. In the "top-down" approach, losses from the high voltage system, through and including distribution substations, were calculated along with power flow data, conductor and transformer loss estimates, and metered poles.

At this point in the analysis, system loads and losses at the input into the distribution substation system are known with reasonable accuracy. However, it is the remaining loads and losses on the distribution substations, primary system, secondary circuits, and services which are generally difficult to estimate. Estimated and actual Company load data provided the starting point for performing a "bottom-up" approach for calculating the remaining distribution losses. Basically, this "bottom-up" approach develops line loadings by first determining loads and losses at each level beginning at a customer's meter service entrance and then going through secondary lines, line transformers, primary lines, and finally distribution substation. These distribution system loads and associated losses are then compared to the initial calculated input into Distribution Substation loadings for reasonableness prior to finalizing the loss factors. An overview of the loss study is shown on Figure 1.

With the emergence of transmission as a stand-alone function throughout various regions of the country, a modification to the historical calculation of the transmission loss factors was required. Historic loss studies recognized the multipath approach to losses from high voltage to low voltage delivery. The current definition of transmission losses recognized in the industry is simply to sum all losses at transmission as an integrated system. This approach will typically increase the resulting composite transmission loss factors but better reflects the topology of the systems with dispersed supply resources and interconnections.

The load research data provided the starting point for performing a "bottom-up" approach for estimating the remaining distribution losses. Basically, this "bottom-up" approach develops line loadings by first determining loads and losses at each level beginning at a customer's meter and service entrance and then going through secondary lines, line transformers, primary lines and finally distribution substation. These distribution system loads and associated losses are then compared to the initial calculated input into Distribution Substation loadings for reasonableness prior to finalizing the loss factors. An overview of the loss study is shown on Figure 1 on the next page.

Table 1, below, provides the final results from Appendix A for the 2017 calendar year. Exhibits 8 and 9 of Appendix A present a more detailed analysis of the final calculated summary results of losses by voltage segments and delivery service level in the Company's power system. These Table 1 cumulative loss expansion factors are applicable only to metered sales at the point of receipt for adjustment to the power system's input level. A separate combined loss factor was also calculated on Exhibit 10 which combines the loss factors from the TNC and TCC on a load weighted basis.

TABLE 1
Loss Factors at Sales Level, Calendar Year 2017

Voltage Level of Service	Total Retail	Distribution Only	TNC/TCC Composite
Demand (kW)			
Transmission[1]	1.02307	1.00000	1.02353
Primary Lines	1.06395	1.03996	1.06761
Secondary	1.08836	1.06381	1.09223
Energy (kWh)			
Transmission[1]	1.01691	1.00000	1.01745
Primary Lines	1.04662	1.02922	1.05080
Secondary	1.07598	1.05808	1.08014
Losses – Net System Input[2]	5.70% MWh 7.25% MW		
Losses – Net System Output[3]	6.05% MWh 7.82% MW		

The loss factors presented in the Delivery Only column of Table 1 are the Total TCC loss factors divided by the transmission loss factor in order to remove these losses from each service level loss factor. For example, the secondary distribution demand loss factor of 1.06381 includes the recovery of all remaining non-transmission losses from the subtransmission, distribution substation, primary lines, line transformers, secondary conductors and services.

[1] Reflects results for 345 kV, 138 kV, and 69 kV.
[2] Net system input equals firm sales plus losses. Company use less non-requirement sales and related losses. See Appendix A, Exhibit 1, for their calculations.
[3] Net system output uses losses divided by output or sales data as a reference.

The net system input shown in Table 1 is the MWh losses of 5.70% for the total TCC load using calculated losses divided by the total input energy to the system. The 6.05% represents the same losses using system output instead of input as a reference. The net system input reference shown in Table 1 represents MW losses of 7.25% and 7.82% losses at output. These results use the appropriate total losses for each but are divided by system output or sales. These calculations are all based on the data and results shown on Exhibits 1, 7 and 9 of the study.

Due to the very nature of losses being primarily a function of equipment loading levels for a peak load hour, the loss factor derivations for any voltage level must consider both the load at that level plus the loads from lower voltages and their associated losses. As a result, cumulative losses on losses equates to additional load at higher levels along with future changes (+ or –) in loads throughout the power system. It is therefore important to recognize that losses are multiplicative in nature (future) and not additive (test year only) for all future years to ensure total recovery based on prospective fixed loss factors for each service voltage.

The derivation of the cumulative loss factors shown in Table 1 have been detailed for all electrical facilities in Exhibit 9, page 1 for demand and page 2 for energy. Beginning on line 1 of page 1 (demand) under the secondary column, metered sales are adjusted for service losses on lines 3 and 4. This new total load (with losses) becomes the load amount for the next higher facilities of secondary conductors and their loss calculations. This process is repeated for all the installed facilities until the secondary sales are at the input level (line 45). The final loss factor for all delivery voltages using this same process is shown on line 46 and Table 1 for demand. This procedure is repeated in Exhibit 9, page 2, for the energy loss factors.

The loss factor calculation is simply the input required (line 45) divided by the metered sales (line 43).

An overview of the loss study is shown on Figure 1 on the next page. Figure 2 simply illustrates the major components that must be considered in a loss analysis.

Figure 1

MANAGEMENT APPLICATIONS CONSULTING, INC.
ELECTRIC LOSS MODEL OVERVIEW

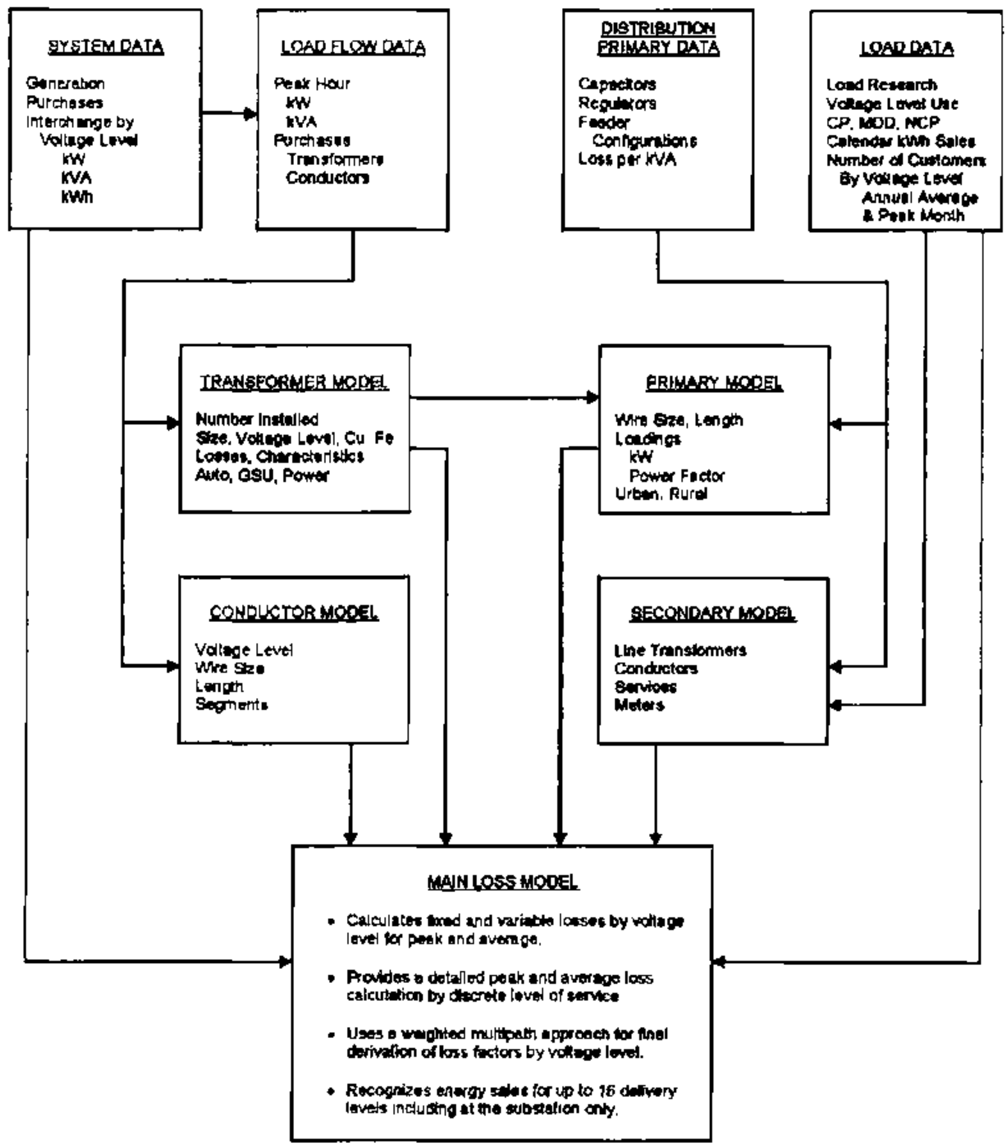
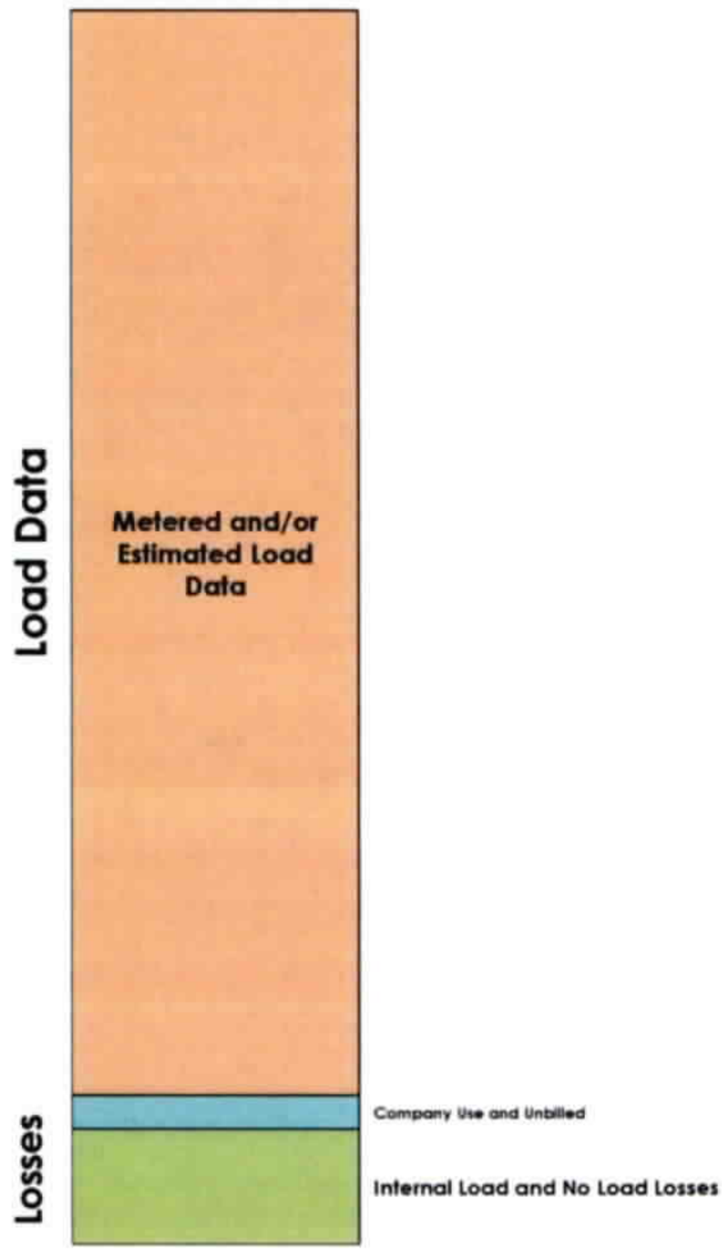


Figure 2
Generic Energy Loss Components



2.0 INTRODUCTION

This report of the 2017 Analysis of System Losses for the TCC power system provides a summary of results, conceptual background or methodology, description of the analyses, and input information related to the study.

2.1 Conduct of Study

Typically, between five to ten percent of the total peak hour MW and annual MWH requirements of an electric utility is lost or unaccounted for in the delivery of power to customers. Investments must be made in facilities which support the total load which includes losses or unaccounted for load. Revenue requirements associated with load losses are an important concern to utilities and regulators in that customers must equitably share in all of these cost responsibilities. Loss expansion factors by voltage level are the mechanism by which customers' metered demand and energy data are mathematically adjusted to the generation or input level (point of reference) when performing cost and revenue calculations.

An acceptable accounting of losses can be determined for any given time period using available engineering, system, and customer data along with empirical relationships. This loss analysis for the delivery of demand and energy utilizes such an approach. A microcomputer loss model[4] is utilized as the vehicle to organize the available data, develop the relationships, calculate the losses, and provide an efficient and timely avenue for future updates and sensitivity analyses. Our procedures and calculations are similar with prior loss studies, and they rely on numerous databases that include customer statistics and power system investments at various voltage levels of service.

Company personnel performed most of the data gathering and data processing efforts and checked for reasonableness. MAC provided assistance as necessary to construct databases, transfer files, perform calculations, and check the reasonableness of results. Efforts in determining the data required to perform the loss analysis centered on information which was available from existing studies or reports within the Company. From an overall perspective, our efforts concentrated on five major areas:

1. System information concerning peak demand and annual energy requirements by voltage level,
2. High voltage power system power flow data and associated loss calculations,
3. Distribution system primary and secondary loss calculations,
4. Derivation of fixed and variable losses by voltage level, and
5. Development of final cumulative expansion factors at each voltage for peak demand (kW) and annual energy (kWh) requirements at the point of delivery (meter).

[1]Copyright by Management Applications Consulting, Inc

2.2 Electric Power Losses

Losses in power systems consist of primarily technical losses with a much smaller level of non-technical losses.

Technical Losses

Electrical losses result from the transmission of energy over various electrical equipment. The largest component of total losses during peaking conditions is power dissipation as a result of varying loading conditions and are oftentimes called load losses which are mostly related to the square of the current (I^2R). These peak hour losses can be very high percent of all technical losses during peak loading conditions. The remaining losses are called no-load and represent essentially fixed (constant) energy losses throughout the year. These no-load losses represent energy required to energize various electrical equipment regardless of their loading levels over the entire year. The major portion of these no-load losses consist of core or magnetizing energy related to installed transformers throughout the power system and generates the major component of annual losses on any distribution system.

The following Table 2 summarizes the unadjusted fixed and variable losses by major functional categories from Exhibit 5 of Appendix A:

TABLE 2

	DEMAND (PEAK HOUR – MW)			ENERGY (ANNUAL AVERAGE – MWH)		
	FIXED	VARIABLE	TOTAL	FIXED	VARIABLE	TOTAL
TRANS	12.02	105.68	117.70	106,800	353,926	460,726
(%)	10.21%	89.79%	100.00%	23 18%	76.82%	100.00%
SUBTRANS	NA	NA	NA	NA	NA	NA
(%)						
DIST SUBS	12 64	14.84	27 47	110,694	52,203	162,897
(%)	45.99%	54.01%	100.00%	67.95%	32.05%	100.00%
PRIMARY	1 44	140.29	141.73	12,610	439,206	451,817
(%)	1 02%	98.98%	100.00%	2.79%	97.21%	100.00%
SECONDARY	44.75	42.03	86.78	392,041	111,716	503,757
(%)	51.57%	48.43%	100.00%	77 82%	22.18%	100 00%
TOTAL SYS	70.85	302 84	373 69	622,146	957,051	1,579,196
(%)	18.96%	81.04%	100.00%	39.40%	60.60%	100.00%
TOTAL DIST	58.83	197.16	255.99	515,345	603,125	1,118,470
(%)	22.98%	77.02%	100.00%	46 08%	53.92%	100.00%

Non-Technical Losses

These are unaccounted for energy losses that are related to energy theft, metering, non-payment by customers, and accounting errors. Losses related to these areas are generally very small and can be extremely difficult and subjective to quantify. Our efforts generally do not develop any meaningful level because we assume that improving technology and utility practices have minimized these amounts.

2.3 Loss Impacts from Distributed Generation (DG)

The impacts of losses on a power system from the installation of various DG facilities will depend somewhat on the penetration level, type of installations and location on a circuit. Based on the results presented in Table 2 of this loss study, the impacts are significantly different from looking at any single peak load hour versus the potential impacts over all hours of an entire year. Use of a typical uniform loss factor(s) for each voltage level may require additional consideration to recognize that a reduced consumption level could have little or no impact due to the recovery requirements for the high level of fixed losses over the entire hourly electric grid condition for any DG location.

2.4 Description of Model

The loss model is a customized applications model, constructed using the Excel software program. Documentation consists primarily of the model equations at each cell location. A significant advantage of such a model is that the actual formulas and their corresponding computed values at each cell of the model are immediately available to the analyst.

A brief description of the three (3) major categories of effort for the preparation of each loss model is as follows:

- Main sheet which contains calculations for all primary and secondary losses, summaries of all conductor and transformer calculations from other sheets discussed below, output reports and supporting results.

- Transformer sheet which contains data input and loss calculations for each distribution substation and high voltage transformer. Separate iron and winding losses are calculated for each transformer by identified type.

- Conductor sheet containing summary data by major voltage level as to circuit miles, loading assumptions, and kW and kWh loss calculations. Separate loss calculations for each line segment were made using the Company's power flow data by line segment and summarized by voltage level in this model.

3.0 METHODOLOGY

3.1 Background

The objective of a Loss Study is to provide a reasonable set of energy (average) and demand (peak) loss expansion factors which account for system losses associated with the transmission and delivery of power to each voltage level over a designated period of time. The focus of this study is to identify the difference between total energy inputs and the associated sales with the difference being equitably allocated to all delivery levels. Several key elements are important in establishing the methodology for calculating and reporting the Company's losses. These elements are:

- Selection of voltage level of services,
- Recognition of losses associated with conductors, transformations, and other electrical equipment/components within voltage levels,
- Identification of customers and loads at various voltage levels of service,
- Review of generation or net power supply input at each level for the test period studied, and
- Analysis of kW and kWh sales by voltage levels within the test period.

The three major areas of data gathering and calculations in the loss analysis were as follows:

1. System Information (monthly and annual)
   - MWH generation and MWH sales.
   - Coincident peak estimates and net power supply input from all sources and voltage levels.
   - Customer load data estimates from available load research information, adjusted MWH sales, and number of customers in the customer groupings and voltage levels identified in the model.
   - System default values, such as power factor, loading factors, and load factors by voltage level.

2. High Voltage System

- Conductor information was summarized from a database by the Company which reflects the transmission system by voltage level. Extensive use was made of the Company's power flow data with the losses calculated and incorporated into the final loss calculations.

- Transformer information was developed in a database to model transformation at each voltage level. Substation power, step-up, and auto transformers were individually identified along with any operating data related to loads and losses.

- Power flow data of peak condition was the primary source of equipment loadings and derivation of load losses in the high voltage loss calculations.

3. Distribution System

- Distribution Substations – Data was developed for modeling each substation as to its size and loading. Loss calculations were performed from this data to determine load and no load losses separately for each transformer.

- Primary lines – Line loading and loss characteristics for several representative primary circuits were obtained from the Company. These loss results developed kW loss per MW of load and a composite average was calculated to derive the primary loss estimate.

- Line transformers – Losses in line transformers were based on each customer service group's size, as well as the number of customers per transformer. Accounting and load data provided the foundation with which to model the transformer loadings and to calculate load and no load losses.

- Secondary network – Typical secondary networks were estimated for conductor sizes, lengths, loadings, and customer penetration for residential and small general service customers.

- Services – Typical services were estimated for each secondary service class of customers identified in the study with respect to type, length, and loading.

The loss analysis was thus performed by constructing the model in segments and subsequently calculating the composite until the constraints of peak demand and energy were met:

- Information as to the physical characteristics and loading of each transformer and conductor segment was modeled.
- Conductors, transformers, and distribution were grouped by voltage level, and unadjusted losses were calculated.
- The loss factors calculated at each voltage level were determined by "compounding" the per-unit losses. Equivalent sales at the supply point were obtained by dividing sales at a specific level by the compounded loss factor to determine losses by voltage level.
- The resulting demand and energy loss expansion factors were then used to adjust all sales to the generation or input level in order to estimate the difference.
- Reconciliation of kW and kWh sales by voltage level using the reported system kW and kWh was accomplished by adjusting the initial loss factor estimates until the mismatch or difference was eliminated.

3.2 Calculations and Analysis

This section provides a discussion of the input data, assumptions, and calculations performed in the loss analysis. Specific appendices have been included in order to provide documentation of the input data utilized in the model.

3.2.1 Bulk, Transmission and Subtransmission Lines

The transmission and subtransmission line losses were calculated based on a modeling of unique voltage levels identified by the Company's power flow data and configuration for the entire integrated TCC Power System. Specific information as to length of line, type of conductor, voltage level, peak load, maximum load, etc., were provided based on Company records and utilized as data input in the loss model.

Actual MW and MVA line loadings were based on TCC's peak loading conditions. Calculations of line losses were performed for each line segment separately and combined by voltage levels for reporting purposes as shown in the Discussion of Results (Section 4.0) of this report. The loss calculations consisted of determining a circuit current value based on MVA line loadings and evaluating the I^2R results for each line segment.

After system coincident peak hour losses were identified for each voltage level, a separate calculation was then made to develop annual average energy losses based on a loss factor approach. Load factors were determined for each voltage level based on system and customer load information. An estimate of the Hoebel coefficient (see Appendix B) was then used to calculate energy losses for the entire period being analyzed. The results are presented in Section 4.0 of this report.

3.2.2 Transformers

The transformer loss analysis required several steps in order to properly consider the characteristics associated with various transformer types; such as, step-up, auto transformers, distribution substations, and line transformers. In addition, further efforts were required to identify both iron and winding losses within each of these transformer types in order to obtain reasonable peak (kW) and average energy (kWh) losses. While iron losses were considered essentially constant for each hour, recognition had to be made for the varying degree of winding losses due to hourly equipment loadings.

Standardized test data tables were used to represent no load information (fixed) and full load (variable) losses for different types and sizes of transformers. This test data was incorporated into the loss model to develop relationships representing winding and iron or core losses for the transformer loss calculation. These results were then totaled by various groups, as identified and discussed in Section 4.0.

The remaining miscellaneous losses considered in the loss study consisted of several areas which do not lend themselves to any reasonable level of modeling for estimating their respective losses and were therefore lumped together into a single loss factor of 0.15%. The typical range of values for these losses is from 0.10% to 0.25%, and we have assumed a lower value to be conservative at this time. The losses associated with this loss factor include bus bars, unmetered station use, grounding transformers, cooling fans, heating and air conditioning requirements, and other remaining station use requirements.

3.2.3 Distribution System

The load data at the substation and customer level, coupled with primary and secondary network information, was sufficient to model the distribution system in adequate detail to calculate losses.

Primary Lines

Primary line loadings take into consideration the available distribution load along with the actual customer loads including losses. Primary line loss estimates were prepared by the Company for use in this loss study. These estimates considered loads per substation, voltage levels, loadings, total circuit miles, wire size, and single- to three-phase investment estimates. All of these factors were considered in calculating the actual demand (kW) and energy (kWh) for the primary system.

Line Transformers

Losses in line transformers were determined based on typical transformer sizes for each secondary customer service group and an estimated or calculated number of customers per transformer. Accounting records and estimates of load data provided the necessary database with which to model the loadings. These calculations also made it possible to determine separate winding and iron losses for distribution line transformers, based on a table of representative losses for various transformer sizes.

Secondary Line Circuits

A calculation of secondary line circuit losses was performed for loads served through these secondary line investments. Estimates of typical conductor sizes, lengths, loadings and customer class penetrations were made to obtain total circuit miles and losses for the secondary network. Customer loads which do not have secondary line requirements were also identified so that a reasonable estimate of losses and circuit miles of these investments could be made.

Service Drops and Meters

Service drops were estimated for each secondary customer reflecting conductor size, length and loadings to obtain demand losses. A separate calculation was also performed using customer maximum demands to obtain kWh losses. Meter loss estimates were also made for each customer and incorporated into the calculations of kW and kWh losses included in the Summary Results.

4.0 DISCUSSION OF RESULTS

A brief description of each Exhibit provided in Appendix A follows:

Exhibit 1 - Summary of Company Data

This exhibit reflects system information used to determine percent losses and a detailed summary of kW and kWh losses by voltage level. The loss factors developed in Exhibit 7 are also summarized by voltage level.

Exhibit 2 - Summary of Conductor Information

A summary of MW and MWH load and no load losses for conductors by voltage levels is presented. The sum of all calculated losses by voltage level is based on input data information provided in Appendix A. Percent losses are based on equipment loadings.

Exhibit 3 - Summary of Transformer Information

This exhibit summarizes transformer losses by various types and voltage levels throughout the system. Load losses reflect the winding portion of transformer losses while iron losses reflect the no load or constant losses. MWH losses are estimated using a calculated loss factor for winding and the test year hours times no load losses.

Exhibit 4 - Summary of Losses Diagram (2 Pages)

This loss diagram represents the inputs and output of power at system peak conditions. Page 1 details information from all points of the power system and what is provided to the distribution system for primary loads. This portion of the summary can be viewed as a "top down" summary into the distribution system.

Page 2 represents a summary of the development of primary line loads and distribution substations based on a "bottom up" approach. Basically, loadings are developed from the customer meter through the Company's physical investments based on load research and other metered information by voltage level to arrive at MW and MVA requirements during peak load conditions by voltage levels.

Exhibit 5 - Summary of Sales and Calculated Losses

Summary of Calculated Losses represents a tabular summary of MW and MWH load and no load losses by discrete areas of delivery within each voltage level. Losses have been identified and are derived based on summaries obtained from Exhibits 2 and 3 and losses associated with meters, capacitors and regulators.

Exhibit 6 - Development of Loss Factors, Unadjusted

This exhibit calculates demand and energy losses and loss factors by specific voltage levels based on sales level requirements. The actual results reflect loads by level and summary totals of losses at that level, or up to that level, based on the results as shown in Exhibit 5. Finally, the estimated values at generation are developed and compared to actual generation to obtain any difference or mismatch.

Exhibit 7 - Development of Loss Factors, Adjusted

The adjusted loss factors are the results of adjusting Exhibit 6 for any difference. All differences between estimated and actual are prorated to each level based on the ratio of each level's total load plus losses to the system total. These new loss factors reflect an adjustment in losses due only to the kW and kWh mismatch.

Exhibit 8 – Adjusted Losses and Loss Factors by Facility

These calculations present an expanded summary detail of Exhibit 7 for each segment of the power system with respect to the flow of power and associated losses from the receipt of energy at the meter to the generation for the TCC power system.

Exhibit 9 – Summary of Losses by Delivery Voltage

These calculations present a reformatted summary of losses presented in Exhibits 7 and 8 by power system delivery segment as calculated by voltage level of service based on reported metered sales.

Exhibit 10 – Composite Summary of Losses for TNC and TCC

These calculations are based on using the individual loss results from their respective Exhibit 7 on a load weighted basis by voltage level of service.

Appendix A

Results of 2017 AEP – TCC Integrated Power System Loss Analysis

AEP TEXAS CENTRAL

EXHIBIT 1

SUMMARY OF COMPANY DATA

ANNUAL PEAK	5,219	MW
ANNUAL GENERATION	27,704,663	MWH
ANNUAL SALES	26,124,565	MWH
SYSTEM LOSSES @ INPUT	1,580,098	or 5.70%
SYSTEM LOSSES @ OUTPUT	1,580,098	or 6.05%
SYSTEM LOAD FACTOR	60.6%	

SUMMARY OF LOSSES - OUTPUT RESULTS

SERVICE	KV	MW	Input	% TOTAL	MWH	Input	% TOTAL
TRANS	345,115,69	117.7	2.26%	31.09%	460,726	1.66%	29.16%
PRIMARY	33,12,1	172.4	3.30%	45.55%	615,209	2.22%	38.93%
SECONDARY	120/240,to,477	88.4	1.69%	23.36%	504,163	1.82%	31.91%
TOTAL		378.6	7.25%	100.00%	1,580,098	5.70%	100.00%

SUMMARY OF LOSS FACTORS

SERVICE	KV	CUMMULATIVE SALES EXPANSION FACTORS DEMAND (Peak) d	1/d	ENERGY (Annual) e	1/e
TOT TRANS	345,115,69	1.02307	0.97745	1.01691	0.98337
PRIMARY	33,12,1	1.06395	0.93989	1.04662	0.95546
SECONDARY	120/240,to,477	1.08836	0.91882	1.07598	0.92939

AEP TEXAS CENTRAL 2017 LOSS ANALYSIS

SUMMARY OF CONDUCTOR INFORMATION

EXHIBIT 2

DESCRIPTION			CIRCUIT MILES	LOADING % RATING	MW LOSSES LOAD	MW LOSSES NO LOAD	MW LOSSES TOTAL	MWH LOSSES LOAD	MWH LOSSES NO LOAD	MWH LOSSES TOTAL
--- BULK ------	345 KV	OR GREATER								
TIE LINES			0.0	0.00%	0.000	0.000	0 000	0	0	0
BULK TRANS			601.6	0.00%	27.400	1.805	29.205	92,169	15,810	107,979
SUBTOT			601.6		27 400	1 805	29 205	92,169	15,810	107,979
--- TRANS ------	69 KV	TO	345.00 KV							
TIE LINES			0	0 00%	0 000	0 000	0 000	0	0	0
TRANS1	115 KV		2,444.8	0.00%	70 510	1.226	71.736	237,184	10,708	247,893
TRANS2	69 KV		1,145.0	0.00%	12.650	0.000	12.650	37,482	0	37,482
SUBTOT			3,589 8		83 160	1 226	84 386	274,666	10,708	285,374
--- SUBTRANS -----	34 KV	TO	69 KV							
TIE LINES			0	0 00%	0 000	0 000	0 000	0	0	0
SUBTRANS1	46 KV		0.0	0.00%	0.000	0.000	0.000	0	0	0
SUBTRANS2	44 KV		0.0	0.00%	0.000	0.000	0 000	0	0	0
SUBTRANS3	34 KV		0.0	0.00%	0.000	0.000	0.000	0	0	0
SUBTOT			0.0		0 000	0 000	0 000	0	0	0
PRIMARY LINES			17,197		140.244	1.440	141.684	439,070	12,610	451,680
SECONDARY LINES			11,625		13 302	0 000	13 302	39,851	0	39,851
SERVICES			13,944		12 082	1.676	13.758	36,897	14,684	51,581
TOTAL			46,957		276.188	6.146	282.335	882,653	53,813	936,465

SUMMARY OF TRANSFORMER INFORMATION EXHIBIT 3

DESCRIPTION		KV VOLTAGE	CAPACITY MVA	NUMBER TRANSFMR	AVERAGE SIZE	LOADING %	MVA LOAD	MW LOSSES LOAD	MW LOSSES NO LOAD	MW LOSSES TOTAL	MWH LOSSES LOAD	MWH LOSSES NO LOAD	MWH LOSSES TOTAL
BULK STEP-UP		345	1,154.0	4	288 5	42.83%	494	0.228	0 753	0 981	767	6,593	7,360
BULK - BULK			0 0	0	0.0	0.00%	0	0.000	0 000	0.000	0	0	0
BULK - TRANS1		115	5,017.0	9	557.4	30.23%	1,517	2.109	3.694	5.804	3,270	32,363	35,633
BULK - TRANS2		69	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
TRANS1 STEP-UP		115	153.0	3	51.0	40.05%	61	0.068	0.252	0.320	229	2,210	2,438
TRANS1 - TRANS2		69	4,949.0	40	123.7	30.38%	1,504	2.517	5.405	7.921	10,101	47,346	57,447
TRANS1-SUBTRANS1		46	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
TRANS1-SUBTRANS2		44	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
TRANS1-SUBTRANS3		34	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
TRANS2 STEP-UP		69	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
TRANS2-SUBTRANS1		46	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
TRANS2-SUBTRANS2		44	0.0	0	0.0	0.00%	0	0.000	0 000	0.000	0	0	0
TRANS2-SUBTRANS3		34	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
SUBTRAN1 STEP-UP		46	0.0	0	0.0	0.00%	0	0.000	0 000	0.000	0	0	0
SUBTRAN2 STEP-UP		44	0.0	0	0.0	0.00%	0	0.000	0.002	0.002	0	0	0
SUBTRAN3 STEP-UP		34	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
SUBTRAN1-SUBTRAN2		44	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
SUBTRAN1-SUBTRAN3		34	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
SUBTRAN2-SUBTRAN3		34	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
DISTRIBUTION SUBSTATIONS													
TRANS1 -	115	33	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
TRANS1 -	115	12	4,863.4	188	25.9	61.25%	2,979	9.476	7 748	17.224	33,438	67,868	101,307
TRANS1 -	115	1	6.5	1	6.5	16.31%	1	0.002	0.012	0.014	7	103	110
TRANS2 -	69	33	0.0	0	0.0	0.00%	0	0.000	0.000	0 000	0	0	0
TRANS2 -	69	12	2,886.3	180	16.0	54.49%	1,573	5.269	4.758	10 027	18,446	41,676	60,122
TRANS2 -	69	1	59.4	14	4.2	38.94%	23	0.091	0.119	0 210	311	1,046	1,357
SUBTRAN1-	46	33	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
SUBTRAN1-	46	12	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
SUBTRAN1-	46	1	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
SUBTRAN2-	44	33	0.0	0	0.0	0.00%	0	0.000	0 000	0.000	0	0	0
SUBTRAN2-	44	12	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
SUBTRAN2-	44	1	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
SUBTRAN3-	34	33	0.0	0	0.0	0.00%	0	0.000	0 000	0.000	0	0	0
SUBTRAN3-	34	12	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
SUBTRAN3-	34	1	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
PRIMARY - PRIMARY			40.0	1	40.0	59.00%	24	0.046	0.041	0.087	137	361	498
LINE TRANSFRMR			15,017.7	300,898	49.9	28.68%	4,307	16.646	43.077	59.723	34,968	377,357	412,325
TOTAL			34,146	301,338				36 452	65 860	102 313	101,674	576,925	678,598

SUMMARY OF LOSSES DIAGRAM - DEMAND MODEL - SYSTEM PEAK 5219 3 MW

BULK TIE LINES
LOAD 0 00% MW
LOAD LOSS 0 000 MW
NOLD LOSS 0 000 MW

BULK LINES
LOADING 0 00%
LOAD LOSS 27 400 MW
NOLD LOSS 1 805 MW

BULK STEP UP
LOADING 42 83%
NO LOAD 0 753 MW
LOAD 0 228 MW
AVG SIZE 288 5 MVA
NUMBER 4

BULK-BULK
LOADING 0 00%
NO LOAD 0 MW
LOAD 0 MW
AVG SIZE 0 MVA
NUMBER 0

TRANS TIE LINES
LOAD 0 00% MW
LOAD LOSS 0 000 MW
NOLD LOSS 0 000 MW

BULK-TRANS1 STEP DOWN
LOADING 30 23%
NO LOAD 3 694 MW
LOAD 2 109 MW
AVG SIZE 557 4444444 MVA
NUMBER 9

TRAN1-TRAN2 STEP DOWN
LOADING 30 38%
NO LOAD 5 405 MW
LOAD 2 517 MW
AVG SIZE 123 725 MVA
NUMBER 40

BULK-TRANS2 STEP DOWN
LOADING 0 00%
NO LOAD 0 000 MW
LOAD 0 000 MW
AVG SIZE 0 MVA
NUMBER 0

TRANS 1&2 STEP UPS
LDNG TR1SU 40 05%
NOLOAD1&2 0 252 MW
LOAD 1&2 0 068 MW
AVSIZ TR1SU 51 0 MVA
NUMBER 3

TRANS1 115 0 KV
LOADING 0 00%
LOAD LOSS 70 510 MW
NOLD LOSS 1 226 MW

TRANS2 69 0 KV
LOADING 0 00%
LOAD LOSS 12 650 MW
NOLD LOSS 0 000 MW

TRANS CUST
SUBS 0 000 MW
0 000 MVA
LINES MW
MVA

SUBTRANS TIE LINES
LOAD 0 00% MW
LOAD LOSS 0 000 MW
NOLD LOSS 0 000 MW

TRANS1&2-SUBTRANS1
LDNG TR2-ST 0 00%
NO LOAD 0 000 MW
LOAD 0 000 MW
AVSIZ TR2 0 MVA
NUMBER 0

SUBTR1&2-SUBTRANS2&3
LOADING 0 00%
NO LOAD 0 000 MW
LOAD 0 000 MW
AVG SIZE 0 MVA
NUMBER 0

TRANS1&2- SUBTRANS2
LDNG TR2-ST 0 00%
NO LOAD 0 000 MW
LOAD 0 000 MW
AVSIZ TR2-ST 0 00 MVA
NUMBER 0

TRANS1&2-SUBTRANS3
LDNG TR2-ST2 0 00%
NO LOAD 0 00
LOAD 0 00
AVSIZ TR2-ST2 0 00
NUMBER 0

SUBTRANS1,2,&3 STEP UPS
LDNG ST1SU 0 00%
NO LOAD 0 002 MW
LOAD 0 000 MW
AVSIZ ST2 0 0 MVA
NUMBER 0

SUBTRANS1 46 KV
LOADING 0 00%
LOAD LOSS 0 000 MW
NOLD LOSS 0 000 MW

SUBTRANS2 44 KV
LOADING 0 00%
LOAD LOSS 0 000 MW
NOLD LOSS 0 000 MW

SUBTRANS2 34 KV
LOADING 0 00%
LOAD LOSS 0 000 MW
NOLD LOSS 0 000 MW

SUBTRANS CUST
SUBS - MW 0 000
MVA 0 000
LINES- MW
MVA

TO DISTRIBUTION SYSTEM
4575 8 MVA 4484 3 MW

TRANS1 2 980 0 MVA
65 13%
115 KV

TRANS2 1 595 8 MVA
34 87%
69 KV

SUBTRANS1 0 0 MVA
0 00%
46 KV

SUBTRANS2 0 0 MVA
0 00%
44 KV

SUBTRANS3 0 0 MVA
0 00%
34 KV

FROM HIGH VOLTAGE SYSTEM

TOTAL 4 576 MVA 4 484 MW

TRANS1	2 980 0 MVA	65 13%	115 KV
TRANS2	1 595 8 MVA	34 87%	69 KV
SUBTRANS1	0 0 MVA	0 00%	46 KV
SUBTRANS2	0 0 MVA	0 00%	44 KV
SUBTRANS3	0 0 MVA	0 00%	34 KV

DISTRIBUTION SYSTEM LOAD

	PRIM1	PRIM2	PRIM3	PRIM1	PRIM2	PRIM3	PRIM1	PRIM2	PRIM3	PRIM1	PRIM2	PRIM3	PRIM1	PRIM2	PRIM3
VOLTAGE	33	12	1	33	12	1	33	12	1	33	12	1	33	12	1
LOAD MVA	0	2 979	1	0	1 573	23	0	0	0	0	0	0	0	0	0
% SYS TOT	0 00%	65 10%	0 02%	0 00%	34 37%	0 51%	0 00%	0 00%	0 00%	0 00%	0 00%	0 00%	0 00%	0 00%	0 00%
NOLD LOSS	0 000	7 748	0 012	0 000	4 758	0 119	0 000	0 000	0 000	0 000	0 000	0 000	0 000	0 000	0 000
LOAD LOSS	0 000	9 476	0 002	0 000	5 269	0 091	0 000	0 000	0 000	0 000	0 000	0 000	0 000	0 000	0 000
AVG SIZE	0 0	25 9	6 5	0 0	16 0	4 2	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0
NUMBER	0	188	1	0	180	14	0	0	0	0	0	0	0	0	0
DIVERSITY RATIO	0 000	1 200	1 200	0 000	1 200	1 200	0 000	0 000	0 000	0 000	0 000	0 000	0 000	0 000	0 000

PRIMARY LINES

LOADING	4456 982	MW
@ SYS PF	4547 940	MVA
LOAD LOSS	140 244	MW
NOLD LOSS	1 440	MW
TOT LOSS	141 684	MW

PRIM/PRIM TRANSF

LOADING	23 601	MW
NOLD LOSS	0 041	MW
LOAD LOSS	0 046	MW
AVG SIZE	40 00	
NUMBER	1	

PRIM CUST LOADS

NO LINES CUST SUB	0 000	MW
	0 000	MVA
NO LINES CO SUB	0 000	MW
	0 000	MVA
PRIM WITH LINES	375 300	MW
	407 935	MVA

LINE TRANSFORMERS

LOADING	3939 911	MW	MVA 4366 360
NOLD LOSS	43 077	MW	
LOAD LOSS	16 646	MW	
AVG SIZE	49 9	KVA	
NUMBER	300896		

SECONDARY LINES

LOAD	1275 622	MW
LOAD LOSS	13 302	MW
NOLD LOSS	0 000	MW
TOT LOSS	13 302	MW

NO SECONDARY LINES

LOAD 2604 566 MW

SERVICES

LOAD	3866 885	MW
LOAD LOSS	12 082	MW
NOLD LOSS	1 676	MW
TOT LOSS	13 758	MW

CUSTOMER SECONDARY LOAD

3853 127 MW

AEP TEXAS CENTRAL 2017 LOSS ANALYSIS

SUMMARY of SALES and CALCULATED LOSSES

EXHIBIT 5

LOSS # AND LEVEL	MW LOAD	NO LOAD +	LOAD =	TOT LOSS	EXP FACTOR	CUM EXP FAC	MWH LOAD	NO LOAD +	LOAD =	TOT LOSS	EXP FACTOR	CUM EXP FAC
1 BULK XFMMR	0.0	0 00	0.00	0 00	0.000000	0 000000	0	0	0	0	0	0
2 BULK LINES	1,077.4	2.56	27.63	30.19	1.028824	1.028824	5,635,800	22,404	92,936	115,340	1.0208931	1.0208931
3 TRANS1 XFMR	1,486.3	3.69	2.11	5.80	1.003920	1.032857	7,811,993	32,363	3,270	35,633	1.0045822	1.0255711
4 TRANS1 LINES	5,984.4	1.48	70.58	72.06	1.012188	1.020448	31,139,081	12,918	237,413	250,331	1.0081043	1.0145714
5 TRANS2TR1 SD	1,473.5	5.40	2.52	7.92	1.005405	1.025963	7,228,254	47,346	10,101	57,447	1.0080113	1.0226994
6 TRANS2BLK SD	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.0000000	0.0000000
7 TRANS2 LINES	1,473.5	0.00	12.65	12.65	1.008660	1.034848	7,228,254	0	37,482	37,482	1.0052125	1.0280302
TOTAL TRAN	5,703.5	13.13	115.48	128.62	1.023071	1.023071	29,839,743	115,031	381,202	496,233	1.0169112	1.0169112
8 STR1BLK SD												
9 STR1T1 SD	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.0000000	0.0000000
10 SRT1T2 SD	0.0	0.00	0.00	0 00	0.000000	0.000000	0	0	0	0	0.0000000	0.0000000
11 SUBTRANS1 LINES	0.0	0.00	0.00	0.00	0.000000	0 000000	0	0	0	0	0.0000000	0 0000000
12 STR2T1 SD	0.0	0.00	0.00	0 00	0.000000	0 000000	0	0	0	0	0.0000000	0 0000000
13 STR2T2 SD	0.0	0 00	0.00	0 00	0.000000	0.000000	0	0	0	0	0.0000000	0 0000000
14 STR2S1 SD	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.0000000	0 0000000
15 SUBTRANS2 LINES	0 0	0 00	0.00	0 00	0.000000	0 000000	0	0	0	0	0.0000000	0 0000000
16 STR3T1 SD	0.0	0 00	0.00	0 00	0.000000	0 000000	0	0	0	0	0.0000000	0 0000000
17 STR3T2 SD	0.0	0 00	0.00	0 00	0.000000	0 000000	0	0	0	0	0.0000000	0 0000000
18 STR3S1 SD	0.0	0 00	0.00	0 00	0.000000	0 000000	0	0	0	0	0.0000000	0 0000000
19 STR3S2 SD	0.0	0 00	0.00	0 00	0.000000	0 000000	0	0	0	0	0.0000000	0 0000000
20 SUBTRANS3 LINES	0 0	0 00	0.00	0 00	0.000000		0	0	0	0	0.0000000	
21 SUBTRANS TOTAL	0.0	0 00	0.00	0 00	0.000000		0	0	0	0	0.0000000	
22 TOT TRANS LOSS FAC	**5,219.3**	**12.02**	**105.68**	**117.70**	**1.023071**	**1.023071**	**27,704,663**	**106,800.10**	**353,926**	**460,726**	**1.0169112**	**1.0169112**
DISTRIBUTION SUBST												
TRANS1	2,920 4	7 76	9.48	17 24	1.005937	1 029145	14,114,006	67,972	33,445	101,417	1.0072376	1 0242711
TRANS2	1,563 9	4 88	5.36	10 24	1.006589	1 029812	7,558,095	42,722	18,757	61,479	1.0082009	1 0252506
SUBTR1	0.0	0 00	0.00	0 00	0.000000	0 000000	0	0	0	0	0.0000000	0 0000000
SUBTR2	0.0	0 00	0.00	0 00	0.000000	0 000000	0	0	0	0	0.0000000	0 0000000
SUBTR3	0.0	0 00	0.00	0 00	0.000000	0 000000	0	0	0	0	0.0000000	0 0000000
WEIGHTED AVERAGE	4,484 3	12 64	14.84	27 47	1.006165	1 029378	21,672,101	110,694	52,203	162,897	1.0075733	1 0246126
PRIMARY INTRCHNGE	0.0				0 000000		0				0.0000000	
PRIMARY LINES	4,456 9	1 44	140.29	141 73	1.032844	1 063187	21,508,982	12,610	439,206	451,817	1.0214567	1 0465973
LINE TRANSF	3,939 9	43 08	16.65	59 72	1.015392	1 079551	18,478,087	377,357	34,968	412,325	1.0228236	1 0704844
SECONDARY	3,880 2	0 00	13.30	13 30	1.003440	1 083265	18,065,762	0	39,851	39,851	1.0022107	1 0728510
SERVICES	3,866 9	1 68	12.08	13 76	1.003571	1 087133	18,025,911	14,684	36,897	51,581	1.0028697	1 0759298
		==========	==========	==========				==========	==========	==========		
TOTAL SYSTEM		70.85	302.84	373.69				622,146	957,051	1,579,196		

DEVELOPMENT of LOSS FACTORS
UNADJUSTED
DEMAND

EXHIBIT 6

LOSS FACTOR LEVEL	CUSTOMER SALES MW a	CALC LOSS TO LEVEL b	SALES MW @ GEN c	CUM PEAK EXPANSION FACTORS d	1/d
BULK LINES	0.0	0.0	0.0	0.00000	0.00000
TRANS SUBS	0.0	0.0	0.0	0.00000	0.00000
TRANS LINES	0.0	0.0	0.0	0.00000	0.00000
SUBTRANS SUBS	0.0	0.0	0.0	0.00000	0.00000
TOTAL TRANS	612.3	14.1	626.4	1.02307	0.97745
PRIM SUBS	0.0	0.0	0.0	0.00000	0.00000
PRIM LINES	375.3	23.7	399.0	1.06319	0.94057
SECONDARY	3,853.1	335.7	4,188.9	1.08713	0.91985
TOTALS	4,840.7	373.6	5,214.3		

DEVELOPMENT of LOSS FACTORS
UNADJUSTED
ENERGY

LOSS FACTOR LEVEL	CUSTOMER SALES MWH a	CALC LOSS TO LEVEL b	SALES MWH @ GEN c	CUM ANNUAL EXPANSION FACTORS d	1/d
BULK LINES	0	0	0	0.00000	0.00000
TRANS SUBS	0	0	0	0.00000	0.00000
TRANS LINES	0	0	0	0.00000	0.00000
SUBTRANS SUBS	0	0	0	0.00000	0.00000
TOTAL TRANS	5,571,157	94,215	5,665,372	1.01691	0.98337
PRIM SUBS	0	0	0	0.00000	0.00000
PRIM LINES	2,579,078	120,178	2,699,256	1.04660	0.95548
SECONDARY	17,974,330	1,364,787	19,339,117	1.07593	0.92943
TOTALS	26,124,565	1,579,180	27,703,745		

ESTIMATED VALUES AT GENERATION

LOSS FACTOR AT VOLTAGE LEVEL	MW	MWH
BULK LINES	0.00	0
TRANS SUBS	0.00	0
TRANS LINES	0.00	0
SUBTRANS SUBS	0.00	0
TOTAL TRANS	626.43	5,665,372
PRIM SUBS	0.00	0
PRIM LINES	399.01	2,699,256
SECONDARY	4,188.86	19,339,117
SUBTOTAL	5,214.30	27,703,745
ACTUAL ENERGY	5,219.30	27,704,663
MISSMATCH	(5.00)	(918)
% MISSMATCH	-0.10%	0.00%

DEVELOPMENT of LOSS FACTORS EXHIBIT 7
ADJUSTED
DEMAND

LOSS FACTOR LEVEL	CUSTOMER SALES MW a	SALES ADJUST b	CALC LOSS TO LEVEL c	SALES MW @ GEN d	CUM PEAK EXPANSION FACTORS e	f=1/e
BULK LINES	0.0	0.0	0.0	0.0	0.00000	0.00000
TRANS SUBS	0.0	0.0	0.0	0.0	0.00000	0.00000
TRANS LINES	0.0	0.0	0.0	0.0	0.00000	0.00000
SUBTRANS SUBS	0.0	0.0	0.0	0.0	0.00000	0.00000
TOTAL TRANS	612.3	0.0	14.1	626.4	1.02307	0.97745
PRIM SUBS	0.0	0.0	0.0	0.0	0.00000	0.00000
PRIM LINES	375.3	0.0	24.0	399.3	1.06395	0.93989
SECONDARY	3,853.1	0.0	340.4	4,193.6	1.08836	0.91882
			378.6			
TOTALS	4,840.7	0.0	378.6	5,219.3	1.07821	<COMPOSITE

DEVELOPMENT of LOSS FACTORS
ADJUSTED
ENERGY

LOSS FACTOR LEVEL	CUSTOMER SALES MWH a	SALES ADJUST b	CALC LOSS TO LEVEL c	SALES MWH @ GEN d	CUM ANNUAL EXPANSION FACTORS e	f=1/e
BULK LINES	0	0	0	0	0.00000	0.00000
TRANS SUBS	0	0	0	0	0.00000	0.00000
TRANS LINES	0	0	0	0	0.00000	0.00000
SUBTRANS SUBS	0	0	0	0	0.00000	0.00000
TOTAL TRANS	5,571,157	0	94,215	5,665,372	1.01691	0.98337
PRIM SUBS	0	0	0	0	0.00000	0.00000
PRIM LINES	2,579,078	0	120,240	2,699,318	1.04662	0.95546
SECONDARY	17,974,330	0	1,365,643	19,339,973	1.07598	0.92939
			1,580,098			
TOTALS	26,124,565	0	1,580,098	27,704,663	1.06048	<COMPOSITE

ESTIMATED VALUES AT GENERATION

LOSS FACTOR AT VOLTAGE LEVEL	MW	MWH
BULK LINES	0.00	0
TRANS SUBS	0.00	0
TRANS LINES	0.00	0
SUBTRANS SUBS	0.00	0
TOTAL TRANS	626.43	5,665,372
PRIM SUBS	0.00	0
PRIM LINES	399.30	2,699,318
SECONDARY	4,193.57	19,339,973
	5,219.30	27,704,663
ACTUAL ENERGY	5,219.30	27,704,663
MISSMATCH	0.00	0
% MISSMATCH	0.00%	0.00%

Adjusted Losses and Loss Factors by Facility EXHIBIT 8

Unadjusted Losses by Segment

		MW	Unadjusted	MWH	Unadjusted
Service Drop Losses		13 76	13 75	51,581	51,580
Secondary Losses		13.30	13.30	39,851	39,850
Line Transformer Losses		59.72	59.70	412,325	412,319
Primary Line Losses		141 73	141.67	451,817	451,810
Distribution Substation Losses		27 47	27 46	162,897	162,894
Transmission System Losses		117.70	117 70	460,726	460,726
Total		373.69	373.57	1,579,196	1,579,180

Mismatch Allocation by Segment

		MW		MWH	
Service Drop Losses		-0 27		-42	
Secondary Losses		-0 26		-33	
Line Transformer Losses		-1.17		-339	
Primary Line Losses		-2.77		-371	
Distribution Substation Losses		-0 54		-134	
Transmission System Losses	0	0.00		0	
Total		-5.00		-918	

Adjusted Losses by Segment

	MW	% of Total	MWH	% of Total
Service Drop Losses	14.02	3.7%	51,623	3.3%
Secondary Losses	13 56	3 6%	39,883	2.5%
Line Transformer Losses	60 86	16.1%	412,657	26.1%
Primary Line Losses	144.44	38.2%	452,181	28.6%
Distribution Substation Losses	28.00	7.4%	163,028	10.3%
Transmission System Losses	117 70	31.1%	460,726	29.2%
Total	378 57	100 0%	1,580,098	100 0%

Loss Factors by Segment

	MW	MWH
Retail Sales from Service Drops	3853.13	17,974,330
Adjusted Service Drop Losses	14.02	51,623
Input to Service Drops	3867.15	18,025,953
Service Drop Loss Factor	**1.00364**	**1.00287**
Output from Secondary	3867.15	18,025,953
Adjusted Secondary Losses	13 56	39,883
Input to Secondary	3880.70	18,065,835
Secondary Conductor Loss Factor	**1.00351**	**1.00221**
Output from Line Transformers	3880.70	18,065,835
Adjusted Line Transformer Losses	60.86	412,657
Input to Line Transformers	3941.57	18,478,493
Line Transformer Loss Factor	**1.01568**	**1.02284**
Retail Sales from Primary	375.30	2,579,078
Req Whls Sales from Primary	0 00	0
Input to Line Transformers	3941.57	18,478,493
Output from Primary Lines	4316.87	21,057,571
Adjusted Primary Line Losses	144.44	452,181
Input to Primary Lines	4461.30	21,509,752
Primary Line Loss Factor	**1.03346**	**1.02147**
Output from Distribution Substations	4461.30	21,509,752
Req. Whls Sales from Substations	0 00	0
Retail Sales from Substations	0.00	0
Adjusted Distribution Substation Losses	28.00	163,028
Input to Distribution Substations	4489.30	21,672,780
Distribution Substation Loss Factor	**1.00628**	**1.00758**
Retail Sales at from Transmission	612 30	5,571,157
Req. Whls Sales AT SubTransmission	0 00	0
Non-Req. Whls Sales AT SubTransmission	0.00	0
Third Party Wheeling Losses	0.00	0
Input to Distribution Substations	4489.30	21,672,780
Output from SubTransmission	5101.60	27,243,937
Adjusted SubTransmission System Losses	117.70	460,726
Input to Transmission	5219.30	27,704,663
TotTransmission System Loss Factor	**1.02307**	**1.01691**

	DEMAND MW		SUMMARY OF LOSSES AND LOSS FACTORS BY DELIVERY VOLTAGE						EXHIBIT 9 PAGE 1 of 2
	SERVICE LEVEL		SALES MW	LOSSES	SECONDARY	PRIMARY	SUBSTATION	SUBTRANS	TRANSMISSION
1	**SERVICES**								
2	SALES		3,653 1		3,853 1				
3	LOSSES			14 0	14 0				
4	INPUT				3 867 1				
5	**EXPANSION FACTOR**	**1.00364**							
6	**SECONDARY**								
7	SALES								
8	LOSSES			13 6	13 6				
9	INPUT				3.880 7				
10	**EXPANSION FACTOR**	**1.00351**							
11	**LINE TRANSFORMER**								
12	SALES								
13	LOSSES			60 9	60 9				
14	INPUT				3 941 6				
15	**EXPANSION FACTOR**	**1.01568**							
16	**PRIMARY**								
17	SECONDARY				3,941 6				
18	SALES		375 3			375 3			
19	LOSSES			144 4	131 9	12 6			
20	INPUT								
21	**EXPANSION FACTOR**	**1.03346**							
22	**SUBSTATION**								
23	PRIMARY				4 073 4	387 9			
24	SALES		0 0				0 0		
25	LOSSES			28 0	25 6	2 4	0 0		
26	INPUT				4 099 0	390 3	0 0		
27	**EXPANSION FACTOR**	**1.00628**							
28	**SUB-TRANSMISSION**								
29	DISTRIBUTION SUBS								
30	SALES								
31	LOSSES								
32	INPUT								
33	**EXPANSION FACTOR**								
34	**TRANSMISSION**								
35	SUBTRANSMISSION								
36	DISTRIBUTION SUBS				4 099 0	390 3	0 0		
37	SALES		612 3						612 3
38	LOSSES			117 7	94 6	9 0	0 0		14 1
39	INPUT				4 193 6	399 3	0 0		626 4
40	**EXPANSION FACTOR**	**1.02307**							
41	**TOTALS** LOSSES			378 6	340 5	24 0	0 0		14 1
42	% OF TOTAL			100%	89 93%	6 34%	0 00%		3 73%
43	SALES		4,840 7		3.853 1	375 3	0 0		612 3
44	% OF TOTAL		100 00%		79 60%	7 75%	0 00%		12 65%
45	INPUT		5 219 3		4 193 6	399 3	0 0		626 4
46	**CUMMULATIVE EXPANSION LOSS FACTORS** (from meter to system input)				1.08836	1.06394	NA		1.02307

ENERGY MWH **SUMMARY OF LOSSES AND LOSS FACTORS BY DELIVERY VOLTAGE** **EXHIBIT 9**

	SERVICE LEVEL		SALES	LOSSES	SECONDARY	PRIMARY	SUBSTATION	SUBTRANS	TRANSMISSION
1	**SERVICES**								
2	SALES		17,974,330		17 974,330				
3	LOSSES			51,623	51,623				
4	INPUT				18 025,953				
5	**EXPANSION FACTOR**	**1.00287**							
6	**SECONDARY**								
7	SALES								
8	LOSSES			39,883	39,883				
9	INPUT				18 065,835				
10	**EXPANSION FACTOR**	**1.00221**							
11	**LINE TRANSFORMER**								
12	SALES								
13	LOSSES			412,657	412,657				
14	INPUT				18 478,493				
15	**EXPANSION FACTOR**	**1 02284**							
16	**PRIMARY**								
17	SECONDARY				18 478,493				
18	SALES		2 579,078 000			2,579,078			
19	LOSSES			452,181	396,799	55 382			
20	INPUT								
21	**EXPANSION FACTOR**	**1.02147**							
22	**SUBSTATION**								
23	PRIMARY				18 875,292	2,634,460			
24	SALES		0				0		
25	LOSSES			163,028	142,853	20 175	0		
26	INPUT				19 018,145	2,854,835	0		
27	**EXPANSION FACTOR**	**1.00758**							
28	**SUB-TRANSMISSION**								
29	DISTRIBUTION SUBS								
30	SALES								
31	LOSSES								
32	INPUT								
33	**EXPANSION FACTOR**								
34	**TRANSMISSION**								
35	SUBTRANSMISSION								
36	DISTRIBUTION SUBS				19 018,145	2,654 635	0		
37	SALES		5,571 157						5 571,157
38	LOSSES			460,726	321,619	44 893	0		94,215
39	INPUT				19 339,764	2,699,528	0		5,665,372
40	**EXPANSION FACTOR**	**1.01691**							
41	**TOTALS** LOSSES			1 580,098	1 365,434	120 450	0		94,215
42	% OF TOTAL			100%	86 41%	7 62%	0 00%		5 96%
43	SALES		26,124,565		17 974,330	2,579 078	0		5,571 157
44	% OF TOTAL		100 00%		68 80%	9 87%	0 00%		21 33%
45	INPUT		27,704,663		19 339,764	2,699 528	0		5,665 372
46	**CUMMULATIVE EXPANSION LOSS FACTORS** (from meter to system input)				**1.07597**	**1.04670**	**NA**		**1.01691**

TCC and TNC | **DEVELOPMENT of LOSS FACTORS** | **EXHIBIT 10**
COMPOSITE | **ADJUSTED** **EXHIBIT 7** | PAGE 1 OF 2
LOSS FACTORS | **DEMAND**

LOSS FACTOR LEVEL	CUSTOMER SALES MW	SALES ADJUST	CALC LOSS TO LEVEL	SALES MW @ GEN	CUM PEAK FACTORS	EXPANTION
	a	b	c	d	e	f=1/e
BULK LINES	0 0	0.0	0.0	0.0	0.00000	0
TRANS SUBS	0 0	0.0	0 0	0 0	0.00000	0
TRANS LINES	0.0	0.0	0.0	0.0	0.00000	0
SUBTRANS SUBS	0 0	0.0	0.0	0.0	0.00000	0
TOTAL TRANS	627 1	0.0	14.8	641.9	1.02353	0 97824
PRIM SUBS	0.0	0.0	0.0	0.0	0.00000	0
PRIM LINES	571.3	0.0	38.6	609.9	1.06761	0.94061
SECONDARY	4,683 8	0.0	432.0	5,115.7	1.09223	0 91849
TOTALS	5,882 2	0.0	485.3	6,367.5	1.08251	<COMPOSITE

DEVELOPMENT of LOSS FACTORS
ADJUSTED
ENERGY

LOSS FACTOR LEVEL	CUSTOMER SALES MWH	SALES ADJUST	CALC LOSS TO LEVEL	SALES MWH @ GEN	CUM ANNU FACTORS	EXPANTION
	a	b	c	d	e	f=1/e
BULK LINES	0	0	0	0	0.00000	0 00000
TRANS SUBS	0	0	0	0	0.00000	0 00000
TRANS LINES	0	0	0	0	0.00000	0.00000
SUBTRANS SUBS	0	0	0	0	0.00000	0.00000
TOTAL TRANS	5,751,071	0	100,343	5,851,414	1 01745	0 98285
PRIM SUBS	0	0	0	0	0.00000	0 00000
PRIM LINES	4,268,133	0	216,821	4,484,954	1.05080	0.95166
SECONDARY	21,719,495	0	1,740,690	23,460,185	1.08014	0.92580
TOTAL	31,738,699	0	2,057,854	33,796,553	1.06484	<COMPOSITE

TCC

DEVELOPMENT of LOSS FACTORS
ADJUSTED EXHIBIT 7
DEMAND

EXHIBIT 10
PAGE 2 OF 2

LOSS FACTOR LEVEL	CUSTOMER SALES MW	SALES ADJUST	CALC LOSS TO LEVEL	SALES MW @ GEN	CUM PEAK FACTORS	EXPANTION
	a	b	c	d	e	f=1/e
BULK LINES	0 0	0	0	0.0	0.00000	0
TRANS SUBS	0 0	0	0	0.0	0.00000	0
TRANS LINES	0.0	0	0	0.0	0.00000	0
SUBTRANS SUBS	0 0	0.0	0.0	0.0	0.00000	0
TOTAL TRANS	612 3	0.0	14.1	626.4	1.02307	0 97824
PRIM SUBS	0.0	0.0	0.0	0.0	0.00000	0
PRIM LINES	375.3	0.0	24.0	399.3	1.06395	0.94061
SECONDARY	3,853 1	0.0	340.4	4,193.6	1.08836	0 91849
TOTALS	4,840 7	0.0	378.6	5,219.3	1.07821	<COMPOSITE

DEVELOPMENT of LOSS FACTORS
ADJUSTED
ENERGY

LOSS FACTOR LEVEL	CUSTOMER SALES MWH	SALES ADJUST	CALC LOSS TO LEVEL	SALES MWH @ GEN	CUM ANNU FACTORS	EXPANTION
	a	b	c	d	e	f=1/e
BULK LINES	0	0	0	0	0.00000	0.00000
TRANS SUBS	0	0	0	0	0.00000	0.00000
TRANS LINES	0	0	0	0	0.00000	0 00000
SUBTRANS SUBS	0	0	0	0	0.00000	0 00000
TOTAL TRANS	5,571,157	0	94,215	5,665,372	1.01691	0.98337
PRIM SUBS	0	0	0	0	0.00000	0.00000
PRIM LINES	2,579,078	0	120,240	2,699,318	1 04662	0 95546
SECONDARY	17,974,330	0	1,365,643	19,339,973	1 07598	0 92939
TOTAL	26,124,565	0	1,580,098	27,704,663	1 06048	<COMPOSITE

TNC

DEVELOPMENT of LOSS FACTORS
ADJUSTED EXHIBIT 7
DEMAND

LOSS FACTOR LEVEL	CUSTOMER SALES MW	SALES ADJUST	CALC LOSS TO LEVEL	SALES MW @ GEN	CUM PEAK FACTORS	EXPANTION
	a	b	c	d	e	f=1/e
BULK LINES	0.0	0	0	0.0	0.00000	0.00000
TRANS SUBS	0 0	0	0	0.0	0.00000	0 00000
TRANS LINES	0.0	0	0	0.0	0.00000	0.00000
SUBTRANS SUBS	0 0	0	0	0.0	0.00000	0.00000
TOTAL TRANS	14 8	0.0	0.6	15.4	1.04250	0 95924
PRIM SUBS	0 0	0.0	0.0	0.0	0.00000	0 00000
PRIM LINES	196.0	0.0	14.6	210.6	1.07461	0.93057
SECONDARY	830.6	0.0	91.5	922.1	1.11018	0.90075
TOTALS	1,041.4	0.0	106.8	1,148.2	1.10252	<COMPOSITE

DEVELOPMENT of LOSS FACTORS
ADJUSTED
ENERGY

LOSS FACTOR LEVEL	CUSTOMER SALES MWH	SALES ADJUST	CALC LOSS TO LEVEL	SALES MWH @ GEN	CUM ANNU FACTORS	EXPANTION
	a	b	c	d	e	f=1/e
BULK LINES	0	0	0	0	0.00000	0.00000
TRANS SUBS	0	0	0	0	0.00000	0 00000
TRANS LINES	0	0	0	0	0.00000	0 00000
SUBTRANS SUBS	0	0	0	0	0.00000	0.00000
TOTAL TRANS	179,914	0	6,128	186,042	1.03406	0 96706
PRIM SUBS	0	0	0	0	0.00000	0 00000
PRIM LINES	1,689,055	0	96,581	1,785,636	1 05718	0 94591
SECONDARY	3,745,165	0	375,047	4,120,212	1.10014	0 90897
TOTAL	5,614,134	0	477,756	6,091,890	1.08510	<COMPOSITE

Appendix B

Discussion of Hoebel Coefficient

COMMENTS ON THE HOEBEL COEFFICIENT

The Hoebel coefficient represents an established industry standard relationship between peak losses and average losses and is used in a loss study to estimate energy losses from peak demand losses. H. F. Hoebel described this relationship in his article, "Cost of Electric Distribution Losses," Electric Light and Power, March 15, 1959. A copy of this article is attached.

Within any loss evaluation study, peak demand losses can readily be calculated given equipment resistance and approximate loading. Energy losses, however, are much more difficult to determine given their time-varying nature. This difficulty can be reduced by the use of an equation which relates peak load losses (demand) to average losses (energy). Once the relationship between peak and average losses is known, average losses can be estimated from the known peak load losses.

Within the electric utility industry, the relationship between peak and average losses is known as the loss factor. For definitional purposes, loss factor is the ratio of the average power loss to the peak load power loss, during a specified period of time. This relationship is expressed mathematically as follows:

(1) $F_{LS} \cong A_{LS} \div P_{LS}$

where: F_{LS} = Loss Factor
A_{LS} = Average Losses
P_{LS} = Peak Losses

The loss factor provides an estimate of the degree to which the load loss is maintained throughout the period in which the loss is being considered. In other words, loss factor is the ratio of the actual kWh losses incurred to the kWh losses which would have occurred if full load had continued throughout the period under study.

Examining the loss factor expression in light of a similar expression for load factor indicates a high degree of similarity. The mathematical expression for load factor is as follows:

(2) $F_{LD} \cong A_{LD} \div P_{LD}$

where: F_{LD} = Load Factor
A_{LD} = Average Load
P_{LD} = Peak Load

This load factor result provides an estimate of the degree to which the load loss is maintained throughout the period in which the load is being considered. Because of the similarities in definition, the loss factor is sometimes called the "load factor of losses." While the definitions are similar, a strict equating of the two factors cannot be made. There does exist, however, a relationship between these two factors which is dependent upon the shape of the load duration curve. Since resistive losses vary as the square of the load, it can be shown mathematically that the loss factor can vary between the extreme limits of load factor and load factor squared. The relationship between load factor and loss factor has become an industry standard and is as follows:

$$(3)\ F_{LS} \cong H*F_{LD}^2 + (1-H)*F_{LD}$$

where:

F_{LS}	=	Loss Factor
F_{LD}	=	Load Factor
H	=	Hoebel Coefficient

As noted in the attached article, the suggested value for H (the Hoebel coefficient) is 0.7. The exact value of H will vary as a function of the shape of the utility's load duration curve. In recent years, values of H have been computed directly for a number of utilities based on EEI load data. It appears on this basis, the suggested value of 0.7 should be considered a lower bound and that values approaching unity may be considered a reasonable upper bound. Based on experience, values of H have ranged from approximately 0.85 to 0.95. The standard default value of 0.9 is generally used.

Inserting the Hoebel coefficient estimate gives the following loss factor relationship using Equation (3):

$$(4)\ F_{LS} \cong 0.90*F_{LD}^2 + 0.10*F_{LD}$$

Once the Hoebel constant has been estimated and the load factor and peak losses associated with a piece of equipment have been estimated, one can calculate the average, or energy losses as follows:

$$(5)\ A_{LS} \cong P_{LS} * [H*F_{LD}^2 + (1-H)*F_{LD}]$$

where:

A_{LS}	=	Average Losses
P_{LS}	=	Peak Losses
H	=	Hoebel Coefficient
F_{LD}	=	Load Factor

Loss studies use this equation to calculate energy losses at each major voltage level in the analysis.

AEP - TEXAS NORTH COMPANY

2017 Analysis of System Losses

January 2019

Final

Prepared by:

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January 10, 2019

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Director Economic Forecasting
American Electric Power
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RE: 2017 LOSS ANALYSIS – TNC

Dear Messrs. Roush and Burnett:

Transmitted herewith are the results of the 2017 Analysis of System Losses for the AEP - Texas North Company's (TNC) power system. Our analysis develops cumulative expansion factors (loss factors) for both demand (peak/kW) and energy (average/kWh) losses by discrete voltage levels applicable to metered sales data. Our analysis considers only technical losses in arriving at our final recommendations.

On behalf of MAC, we appreciate the opportunity to assist you in performing the loss analysis contained herein. The level of detailed load research and sales data by voltage level, coupled with a summary of power flow data and power system model, forms the foundation for determining reasonable and representative power losses on the TNC system. Our review of these data and calculated loss results support the proposed loss factors as presented herein for your use in various retail cost of service, rate studies, and demand analyses.

Should you require any additional information, please let us know at your earliest convenience.

Sincerely,

Paul M. Normand

Paul M. Normand
Principal

Enclosure
PMN

AEP - Texas North Company
2017 Analysis of System Losses

TABLE OF CONTENTS

AEP - Texas North Company
2017 Analysis of System Losses

1.0 EXECUTIVE SUMMARY

This report presents AEP - Texas North Company's (TNC) 2017 Analysis of System Losses for the power systems as performed by Management Applications Consulting, Inc. (MAC). The study developed separate demand (kW) and energy (kWh) loss factors for each voltage level of service in the power system for TNC. The cumulative loss factor results by voltage level, as presented herein, can be used to adjust metered kW and kWh sales data for losses in performing cost of service studies, determining voltage discounts, and other analyses which may require a loss adjustment.

The procedures used in the overall loss study were similar to prior studies and emphasized the use of "in house" resources where possible. To this end, extensive use was made of the Company's peak hour power flow data and transformer plant investments in the model. In addition, measured and estimated load data provided a means of calculating reasonable estimates of losses by using a "top-down" and "bottom-up" procedure. In the "top-down" approach, losses from the high voltage system, through and including distribution substations, were calculated along with power flow data, conductor and transformer loss estimates, and metered poles.

At this point in the analysis, system loads and losses at the input into the distribution substation system are known with reasonable accuracy. However, it is the remaining loads and losses on the distribution substations, primary system, secondary circuits, and services which are generally difficult to estimate. Estimated and actual Company load data provided the starting point for performing a "bottom-up" approach for calculating the remaining distribution losses. Basically, this "bottom-up" approach develops line loadings by first determining loads and losses at each level beginning at a customer's meter service entrance and then going through secondary lines, line transformers, primary lines, and finally distribution substation. These distribution system loads and associated losses are then compared to the initial calculated input into Distribution Substation loadings for reasonableness prior to finalizing the loss factors. An overview of the loss study is shown on Figure 1.

With the emergence of transmission as a stand-alone function throughout various regions of the country, a modification to the historical calculation of the transmission loss factors was required. Historic loss studies recognized the multipath approach to losses from high voltage to low voltage delivery. The current definition of transmission losses recognized in the industry is simply to sum all losses at transmission as an integrated system. This approach will typically increase the resulting composite transmission loss factors but better reflects the topology of the systems with dispersed supply resources and interconnections.

The load research data provided the starting point for performing a "bottom-up" approach for estimating the remaining distribution losses. Basically, this "bottom-up" approach develops line loadings by first determining loads and losses at each level beginning at a customer's meter and service entrance and then going through secondary lines, line transformers, primary lines and finally distribution substation. These distribution system loads and associated losses are then compared to the initial calculated input into Distribution Substation loadings for reasonableness prior to finalizing the loss factors. An overview of the loss study is shown on Figure 1 on the next page.

Table 1, below, provides the final results from Appendix A for the 2017 calendar year. Exhibits 8 and 9 of Appendix A present a more detailed analysis of the final calculated summary results of losses by voltage segments and delivery service level in the Company's power system. These Table 1 cumulative loss expansion factors are applicable only to metered sales at the point of receipt for adjustment to the power system's input level. A separate combined loss factor was also calculated on Exhibit 10 which combines the loss factors from TNC and TCC on a load weighted basis.

TABLE 1
Loss Factors at Metered Sales Level, Calendar Year 2017

Voltage Level of Service	Total Retail	Distribution Only	TNC/TCC Composite
Demand (kW)			
Transmission[1]	1.04250	1.00000	1.02353
Primary Substation			
Primary Lines	1.07461	1.03081	1.06761
Secondary	1.11018	1.06492	1.09223
Energy (kWh)			
Transmission[1]	1.03406	1.00000	1.01745
Primary Substation			
Primary Lines	1.05718	1.02236	1.05080
Secondary	1.10014	1.06391	1.08014
Losses – Net System Input[2]	7.84% MWH 9.30% MW		
Losses – Net System Output[3]	8.51% MWH 10.25% MW		

The loss factors presented in the Delivery Only column of Table 1 are the Total TNC loss factors divided by the transmission loss factor in order to remove these losses from each service level loss factor. For example, the secondary distribution demand loss factor of 1.06492 includes the recovery of all remaining non-transmission losses from the subtransmission, distribution substation, primary lines, line transformers, secondary conductors and services.

[1] Reflects service at 345 kV, 138 kV and 69 kV.
[2] Net system input equals firm sales plus losses. Company use less non-requirement sales and related losses. See Appendix A, Exhibit 1, for their calculations.
[3] Net system output uses losses divided by output or sales data as a reference.

The net system input shown in Table 1 represents the MWh losses of 7.84% for the total TNC load using calculated losses divided by the associated input energy to the system. The 9.30% represents the same losses using system output instead of input as a reference. The net system output reference shown in Table 1 represents MWh losses of 8.51% and MW losses of 10.25%. These results use the appropriate total losses for each but are divided by system output or sales. These calculations are all based on the data and results shown on Exhibits 1, 7 and 9 of the study.

Due to the very nature of losses being primarily a function of equipment loading levels for a peak load hour, the loss factor derivations for any voltage level must consider both the load at that level plus the loads from lower voltages and their associated losses. As a result, cumulative losses on losses equates to additional load at higher levels along with future changes (+ or −) in loads throughout the power system. It is therefore important to recognize that losses are multiplicative in nature (future) and not additive (test year only) for all future years to ensure total recovery based on prospective fixed loss factors for each service voltage.

The derivation of the cumulative loss factors shown in Table 1 have been detailed for all electrical facilities in Exhibit 9, page 1 for demand and page 2 for energy. Beginning on line 1 of page 1 (demand) under the secondary column, metered sales are adjusted for service losses on lines 3 and 4. This new total load (with losses) becomes the load amount for the next higher facilities of secondary conductors and their loss calculations. This process is repeated for all the installed facilities until the secondary sales are at the input level (line 45). The final loss factor for all delivery voltages using this same process is shown on line 46 and Table 1 for demand. This procedure is repeated in Exhibit 9, page 2, for the energy loss factors.

The loss factor calculation is simply the input required (line 45) divided by the metered sales (line 2).

An overview of the loss study is shown on Figure 1 on the next page. Figure 2 simply illustrates the major components that must be considered in a loss analysis.

Figure 1

MANAGEMENT APPLICATIONS CONSULTING, INC. ELECTRIC LOSS MODEL OVERVIEW

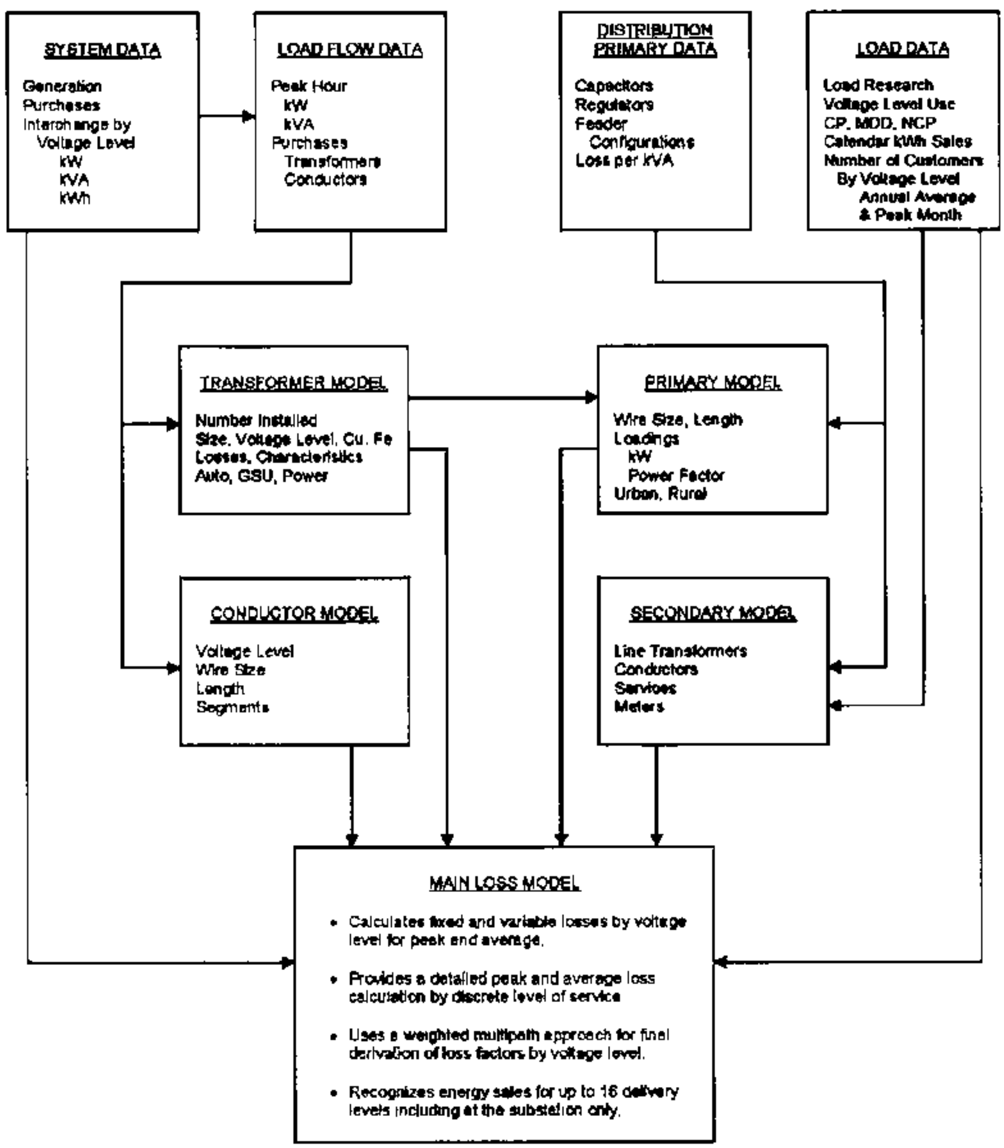
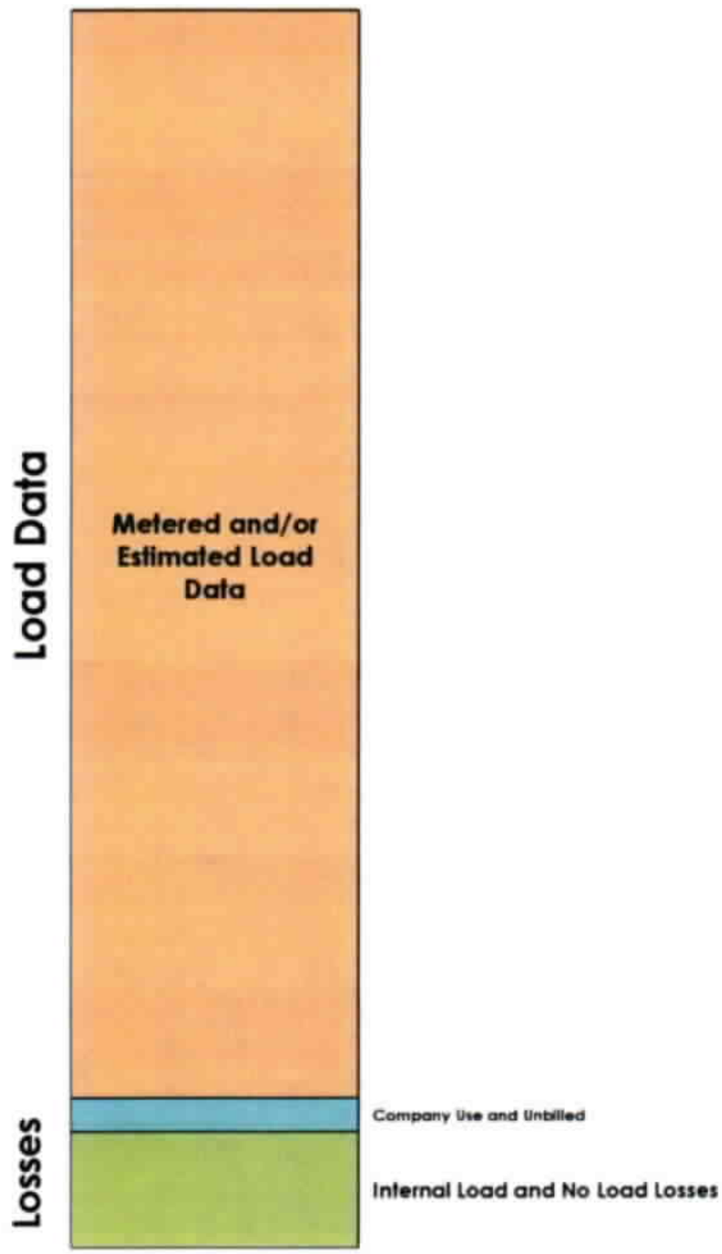


Figure 2
Generic Energy Loss Components



2.0 INTRODUCTION

This report of the 2017 Analysis of System Losses for the TNC power system provides a summary of results, conceptual background or methodology, description of the analyses, and input information related to the study.

2.1 Conduct of Study

Typically, between five to ten percent of the total peak hour MW and annual MWH requirements of an electric utility is lost or unaccounted for in the delivery of power to customers. Investments must be made in facilities which support the total load which includes losses or unaccounted for load. Revenue requirements associated with load losses are an important concern to utilities and regulators in that customers must equitably share in all of these cost responsibilities. Loss expansion factors by voltage level are the mechanism by which customers' metered demand and energy data are mathematically adjusted to the generation or input level (point of reference) when performing cost and revenue calculations.

An acceptable accounting of losses can be determined for any given time period using available engineering, system, and customer data along with empirical relationships. This loss analysis for the delivery of demand and energy utilizes such an approach. A microcomputer loss model[4] is utilized as the vehicle to organize the available data, develop the relationships, calculate the losses, and provide an efficient and timely avenue for future updates and sensitivity analyses. Our procedures and calculations are similar with prior loss studies, and they rely on numerous databases that include customer statistics and power system investments at various voltage levels of service.

Company personnel performed most of the data gathering and data processing efforts and checked for reasonableness. MAC provided assistance as necessary to construct databases, transfer files, perform calculations, and check the reasonableness of results. Efforts in determining the data required to perform the loss analysis centered on information which was available from existing studies or reports within the Company. From an overall perspective, our efforts concentrated on five major areas:

1. System information concerning peak demand and annual energy requirements by voltage level,
2. High voltage power system power flow data and associated loss calculations,
3. Distribution system primary and secondary loss calculations,
4. Derivation of fixed and variable losses by voltage level, and
5. Development of final cumulative expansion factors at each voltage for peak demand (kW) and annual energy (kWh) requirements at the point of delivery (meter).

[1]Copyright by Management Applications Consulting, Inc

2.2 Electric Power Losses

Losses in power systems consist of primarily technical losses with a much smaller level of non-technical losses.

Technical Losses

Electrical losses result from the transmission of energy over various electrical equipment. The largest component of total losses during peaking conditions is power dissipation as a result of varying loading conditions and are oftentimes called load losses which are mostly related to the square of the current (I^2R). These peak hour losses can be a really high percentage of all technical losses during peak loading conditions. The remaining losses are called no-load and represent essentially fixed (constant) energy losses throughout the year. These no-load losses represent energy required to energize various electrical equipment regardless of their loading levels over the entire year. The major portion of these no-load losses consists of core or magnetizing energy related to installed transformers throughout the power system and generates the major component of annual losses on any distribution system.

The following Table 2 summarizes the unadjusted fixed and variable losses by major functional categories from Exhibit 5 of Appendix A:

TABLE 2

	DEMAND (PEAK HOUR)			ENERGY (ANNUAL AVERAGE)		
	FIXED	VARIABLE	TOTAL	FIXED	VARIABLE	TOTAL
TRANS	7.44	55.72	63.16	65,149	212,435	277,583
(%)	11.78%	88.22%	100.00%	23 47%	76 53%	100.00%
SUBTRANS	N/A	N/A	N/A	N/A	N/A	N/A
(%)						
DIST SUBS	4 10	2 82	6 92	35,934	10,589	46,523
(%)	59.28%	40.72%	100.00%	77 24%	22.76%	100.00%
PRIMARY	0 48	24.24	24.72	4,242	75,882	80,124
(%)	1 96%	98.04%	100.00%	5.29%	94 71%	100 00%
SECONDARY	12.79	14.03	26.82	112,055	42,160	154,215
(%)	47.69%	52 31%	100.00%	72 66%	27 34%	100.00%
TOTAL SYS	24.82	96 81	121.62	217,380	341,066	558,446
(%)	20.40%	79.60%	100.00%	38.93%	61.07%	100.00%
TOTAL DIST	17.38	41.09	58 46	152,231	128,631	280,862
(%)	29.72%	70.28%	100.00%	54 20%	45.80%	100.00%

Non-Technical Losses

These are unaccounted for energy losses that are related to energy theft, metering, non-payment by customers, and accounting errors. Losses related to these areas are generally very small and can be extremely difficult and subjective to quantify. Our efforts generally do not develop any meaningful level because we assume that improving technology and utility practices have minimized these amounts.

2.3 Loss Impacts from Distributed Generation (DG)

The impacts of losses on a power system from the installation of various DG facilities will depend somewhat on the penetration level, type of installations and location on a circuit. Based on the results presented in Table 2 of this loss study, the impacts are significantly different from looking at any single peak load hour versus the potential impacts over all hours of an entire year. Use of a typical uniform loss factor(s) for each voltage level may require additional consideration to recognize that a reduced consumption level could have little or no impact due to the recovery requirements for the high level of fixed losses over the entire hourly electric grid condition for any DG location.

2.4 Description of Model

The loss model is a customized applications model, constructed using the Excel software program. Documentation consists primarily of the model equations at each cell location. A significant advantage of such a model is that the actual formulas and their corresponding computed values at each cell of the model are immediately available to the analyst.

A brief description of the three (3) major categories of effort for the preparation of each loss model is as follows:

- Main sheet which contains calculations for all primary and secondary losses, summaries of all conductor and transformer calculations from other sheets discussed below, output reports and supporting results.

- Transformer sheet which contains data input and loss calculations for each distribution substation and high voltage transformer. Separate iron and winding losses are calculated for each transformer by identified type.

- Conductor sheet containing summary data by major voltage level as to circuit miles, loading assumptions, and kW and kWh loss calculations. Separate loss calculations for each line segment were made using the Company's power flow data by line segment and summarized by voltage level in this model.

3.0 METHODOLOGY

3.1 Background

The objective of a Loss Study is to provide a reasonable set of energy (average) and demand (peak) loss expansion factors which account for system losses associated with the transmission and delivery of power to each voltage level over a designated period of time. The focus of this study is to identify the difference between total energy inputs and the associated sales with the difference being equitably allocated to all delivery levels. Several key elements are important in establishing the methodology for calculating and reporting the Company's losses. These elements are:

- Selection of voltage level of services,
- Recognition of losses associated with conductors, transformations, and other electrical equipment/components within voltage levels,
- Identification of customers and loads at various voltage levels of service,
- Review of generation or net power supply input at each level for the test period studied, and
- Analysis of kW and kWh sales by voltage levels within the test period.

The three major areas of data gathering and calculations in the loss analysis were as follows:

1. System Information (monthly and annual)
    - MWH generation and MWH sales.
    - Coincident peak estimates and net power supply input from all sources and voltage levels.
    - Customer load data estimates from available load research information, adjusted MWH sales, and number of customers in the customer groupings and voltage levels identified in the model.
    - System default values, such as power factor, loading factors, and load factors by voltage level.

2. High Voltage System

- Conductor information was summarized from a database by the Company which reflects the transmission system by voltage level. Extensive use was made of the Company's power flow data with the losses calculated and incorporated into the final loss calculations.

- Transformer information was developed in a database to model transformation at each voltage level. Substation power, step-up, and auto transformers were individually identified along with any operating data related to loads and losses.

- Power flow data of peak condition was the primary source of equipment loadings and derivation of load losses in the high voltage loss calculations.

3. Distribution System

- Distribution Substations – Data was developed for modeling each substation as to its size and loading. Loss calculations were performed from this data to determine load and no load losses separately for each transformer.

- Primary lines – Line loading and loss characteristics for several representative primary circuits were obtained from the Company. These loss results developed kW loss per MW of load and a composite average was calculated to derive the primary loss estimate.

- Line transformers – Losses in line transformers were based on each customer service group's size, as well as the number of customers per transformer. Accounting and load data provided the foundation with which to model the transformer loadings and to calculate load and no load losses.

- Secondary network – Typical secondary networks were estimated for conductor sizes, lengths, loadings, and customer penetration for residential and small general service customers.

- Services – Typical services were estimated for each secondary service class of customers identified in the study with respect to type, length, and loading.

The loss analysis was thus performed by constructing the model in segments and subsequently calculating the composite until the constraints of peak demand and energy were met:

- Information as to the physical characteristics and loading of each transformer and conductor segment was modeled.
- Conductors, transformers, and distribution were grouped by voltage level, and unadjusted losses were calculated.
- The loss factors calculated at each voltage level were determined by "compounding" the per-unit losses. Equivalent sales at the supply point were obtained by dividing sales at a specific level by the compounded loss factor to determine losses by voltage level.
- The resulting demand and energy loss expansion factors were then used to adjust all sales to the generation or input level in order to estimate the difference.
- Reconciliation of kW and kWh sales by voltage level using the reported system kW and kWh was accomplished by adjusting the initial loss factor estimates until the mismatch or difference was eliminated.

3.2 Calculations and Analysis

This section provides a discussion of the input data, assumptions, and calculations performed in the loss analysis. Specific appendices have been included in order to provide documentation of the input data utilized in the model.

3.2.1 Bulk, Transmission and Subtransmission Lines

The transmission and subtransmission line losses were calculated based on a modeling of unique voltage levels identified by the Company's power flow data and configuration for the entire integrated TNC Power System. Specific information as to length of line, type of conductor, voltage level, peak load, maximum load, etc., were provided based on Company records and utilized as data input in the loss model.

Actual MW and MVA line loadings were based on TNC's peak loading conditions. Calculations of line losses were performed for each line segment separately and combined by voltage levels for reporting purposes as shown in the Discussion of Results (Section 4.0) of this report. The loss calculations consisted of determining a circuit current value based on MVA line loadings and evaluating the I^2R results for each line segment.

After system coincident peak hour losses were identified for each voltage level, a separate calculation was then made to develop annual average energy losses based on a loss factor approach. Load factors were determined for each voltage level based on system and customer load information. An estimate of the Hoebel coefficient (see Appendix B) was then used to calculate energy losses for the entire period being analyzed. The results are presented in Section 4.0 of this report.

3.2.2 Transformers

The transformer loss analysis required several steps in order to properly consider the characteristics associated with various transformer types; such as, step-up, auto transformers, distribution substations, and line transformers. In addition, further efforts were required to identify both iron and winding losses within each of these transformer types in order to obtain reasonable peak (kW) and average energy (kWh) losses. While iron losses were considered essentially constant for each hour, recognition had to be made for the varying degree of winding losses due to hourly equipment loadings.

Standardized test data tables were used to represent no load information (fixed) and full load (variable) losses for different types and sizes of transformers. This test data was incorporated into the loss model to develop relationships representing winding and iron or core losses for the transformer loss calculation. These results were then totaled by various groups, as identified and discussed in Section 4.0.

The remaining miscellaneous losses considered in the loss study consisted of several areas which do not lend themselves to any reasonable level of modeling for estimating their respective losses and were therefore lumped together into a single loss factor of 0.10%. The typical range of values for these losses is from 0.10% to 0.25%, and we have assumed the lower value to be conservative at this time. The losses associated with this loss factor include bus bars, unmetered station use, grounding transformers, cooling fans, heating and air conditioning requirements, and other remaining station use requirements.

3.2.3 Distribution System

The load data at the substation and customer level, coupled with primary and secondary network information, was sufficient to model the distribution system in adequate detail to calculate losses.

Primary Lines

Primary line loadings take into consideration the available distribution load along with the actual customer loads including losses. Primary line loss estimates were prepared by the Company for use in this loss study. These estimates considered loads per substation, voltage levels, loadings, total circuit miles, wire size, and single- to three-phase investment estimates. All of these factors were considered in calculating the actual demand (kW) and energy (kWh) for the primary system.

Line Transformers

Losses in line transformers were determined based on typical transformer sizes for each secondary customer service group and an estimated or calculated number of customers per transformer. Accounting records and estimates of load data provided the necessary database with which to model the loadings. These calculations also made it possible to determine separate winding and iron losses for distribution line transformers, based on a table of representative losses for various transformer sizes.

Secondary Line Circuits

A calculation of secondary line circuit losses was performed for loads served through these secondary line investments. Estimates of typical conductor sizes, lengths, loadings and customer class penetrations were made to obtain total circuit miles and losses for the secondary network. Customer loads which do not have secondary line requirements were also identified so that a reasonable estimate of losses and circuit miles of these investments could be made.

Service Drops and Meters

Service drops were estimated for each secondary customer reflecting conductor size, length and loadings to obtain demand losses. A separate calculation was also performed using customer maximum demands to obtain kWh losses. Meter loss estimates were also made for each customer and incorporated into the calculations of kW and kWh losses included in the Summary Results.

4.0 DISCUSSION OF RESULTS

A brief description of each Exhibit provided in Appendix A follows:

Exhibit 1 - Summary of Company Data

This exhibit reflects system information used to determine percent losses and a detailed summary of kW and kWh losses by voltage level. The loss factors developed in Exhibit 7 are also summarized by voltage level.

Exhibit 2 - Summary of Conductor Information

A summary of MW and MWH load and no load losses for conductors by voltage levels is presented. The sum of all calculated losses by voltage level is based on input data information provided in Appendix A. Percent losses are based on equipment loadings.

Exhibit 3 - Summary of Transformer Information

This exhibit summarizes transformer losses by various types and voltage levels throughout the system. Load losses reflect the winding portion of transformer losses while iron losses reflect the no load or constant losses. MWH losses are estimated using a calculated loss factor for winding and the test year hours times no load losses.

Exhibit 4 - Summary of Losses Diagram (2 Pages)

This loss diagram represents the inputs and output of power at system peak conditions. Page 1 details information from all points of the power system and what is provided to the distribution system for primary loads. This portion of the summary can be viewed as a "top down" summary into the distribution system.

Page 2 represents a summary of the development of primary line loads and distribution substations based on a "bottom up" approach. Basically, loadings are developed from the customer meter through the Company's physical investments based on load research and other metered information by voltage level to arrive at MW and MVA requirements during peak load conditions by voltage levels.

Exhibit 5 - Summary of Sales and Calculated Losses

Summary of Calculated Losses represents a tabular summary of MW and MWH load and no load losses by discrete areas of delivery within each voltage level. Losses have been identified and are derived based on summaries obtained from Exhibits 2 and 3 and losses associated with meters, capacitors and regulators.

Exhibit 6 - Development of Loss Factors, Unadjusted

This exhibit calculates demand and energy losses and loss factors by specific voltage levels based on sales level requirements. The actual results reflect loads by level and summary totals of losses at that level, or up to that level, based on the results as shown in Exhibit 5. Finally, the estimated values at generation are developed and compared to actual generation to obtain any difference or mismatch.

Exhibit 7 - Development of Loss Factors, Adjusted

The adjusted loss factors are the results of adjusting Exhibit 6 for any difference. All differences between estimated and actual are prorated to each level based on the ratio of each level's total load plus losses to the system total. These new loss factors reflect an adjustment in losses due only to the kW and kWh mismatch.

Exhibit 8 – Adjusted Losses and Loss Factors by Facility

These calculations present an expanded summary detail of Exhibit 7 for each segment of the power system with respect to the flow of power and associated losses from the receipt of energy at the meter to the generation for the TNC power system.

Exhibit 9 – Summary of Losses by Delivery Voltage

These calculations present a reformatted summary of losses presented in Exhibits 7 and 8 by power system delivery segment as calculated by voltage level of service based on reported metered sales.

Exhibit 10 – Composite Summary of Losses for TNC and TCC

These calculations are based on using the individual loss results from their respective Exhibit 7 on a load weighted basis by voltage level of service.

Appendix A

Results of 2017 AEP – TNC Integrated Power System Loss Analysis

AEP TEXAS NORTH

EXHIBIT 1

SUMMARY OF COMPANY DATA

ANNUAL PEAK	1,148	MW
ANNUAL GENERATION	6,091,890	MWH
ANNUAL SALES	5,614,134	MWH
SYSTEM LOSSES @ INPUT	477,756	or 7.84%
SYSTEM LOSSES @ OUTPUT	477,756	or 8.51%
SYSTEM LOAD FACTOR	60.6%	

SUMMARY OF LOSSES - OUTPUT RESULTS

SERVICE	KV	MW	MW Input	% TOTAL	MWH	MWH Input	% TOTAL
TRANS	345,161,115 66,46,20	49.9	4.35%	46.77%	220,266	3.62%	46.10%
PRIMARY	12,4,1	30.8	2.68%	28.81%	116,108	1.91%	24.30%
SECONDARY	120/240,to,477	26.1	2.27%	24.42%	141,382	2.32%	29.59%
TOTAL		106.8	9.30%	100.00%	477,756	7.84%	100.00%

SUMMARY OF LOSS FACTORS

SERVICE	KV	CUMMULATIVE SALES EXPANSION FACTORS DEMAND (Peak) d	1/d	ENERGY (Annual) e	1/e
TOT TRANS	345,161,115 66,46,20	1.04250	0.95924	1.03406	0.96706
PRIM SUBS	12,4	0.00000	0.00000	0.00000	0.00000
PRIMARY	12,4,1	1.07461	0.93057	1.05718	0.94591
SECONDARY	120/240,to,477	1.11018	0.90075	1.10014	0.90897

AEP TEXAS NORTH 2017 LOSS ANALYSIS

SUMMARY OF CONDUCTOR INFORMATION

EXHIBIT 2

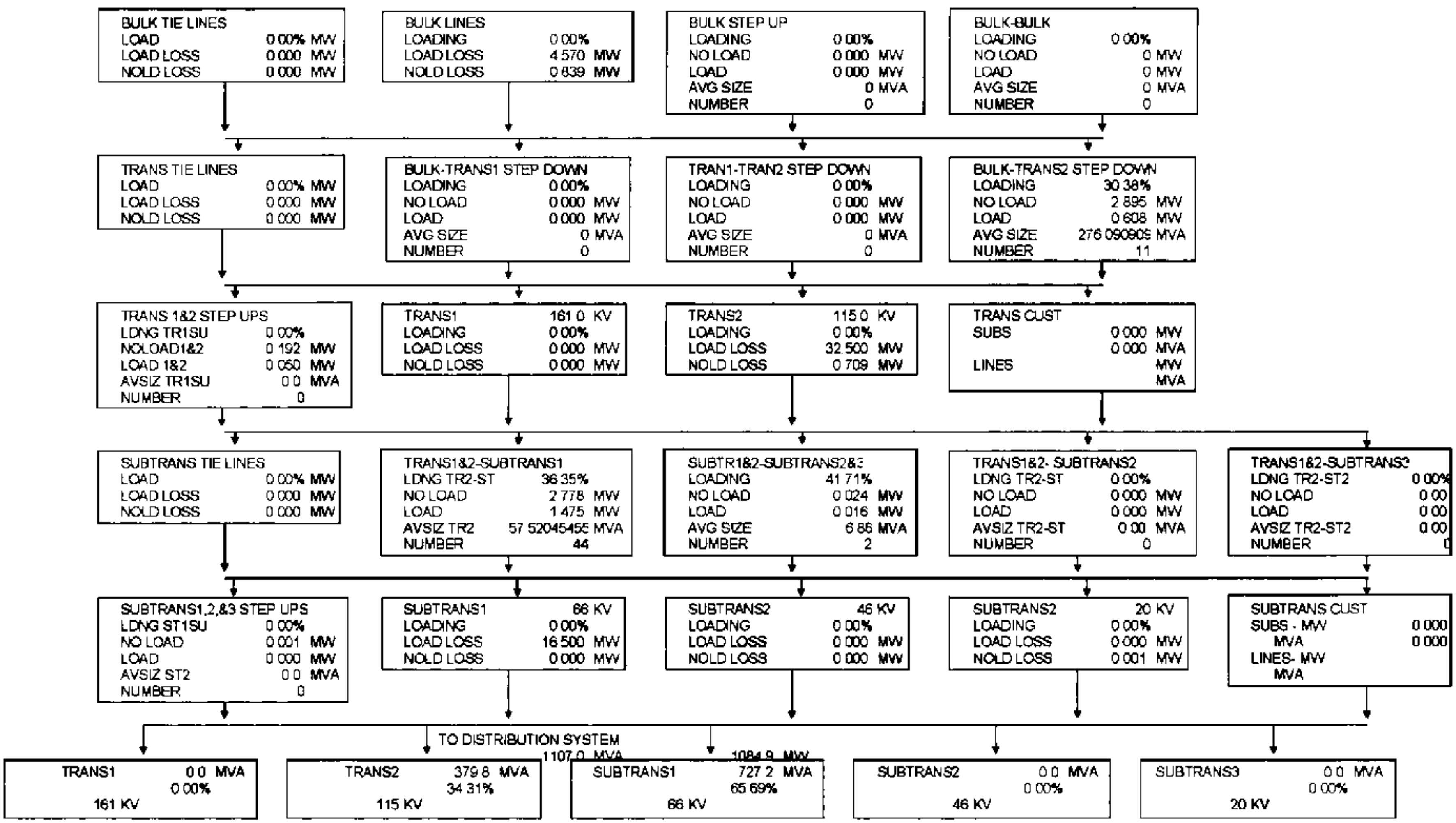
DESCRIPTION			CIRCUIT MILES	LOADING % RATING	MW LOSSES LOAD	MW LOSSES NO LOAD	MW LOSSES TOTAL	MWH LOSSES LOAD	MWH LOSSES NO LOAD	MWH LOSSES TOTAL
-- BULK --------	345 KV	OR GREATER								
TIE LINES			0.0	0.00%	0.000	0.000	0.000	0	0	0
BULK TRANS			279.7		4.570	0.839	5.409	15,849	7,351	23,199
SUBTOT			279.7		4.570	0.839	5.409	15,849	7,351	23,199
-- TRANS ---------	115 KV	TO	345.00 KV							
TIE LINES			0	0.00%	0.000	0.000	0.000	0	0	0
TRANS1	161 KV		0.0	0.00%	0.000	0.000	0.000	0	0	0
TRANS2	115 KV		1,417.4		32.500	0.709	33.209	112,710	6,208	118,918
SUBTOT			1,417.4		32.500	0.709	33.209	112,710	6,208	118,918
-- SUBTRANS ------	20 KV	TO	115 KV							
TIE LINES			0	0.00%	0.000	0.000	0.000	0	0	0
SUBTRANS1	66 KV		2,201.2	0.00%	16.500	0.000	16.500	57,222	0	57,222
SUBTRANS2	46 KV		0.0	0.00%	0.000	0.000	0.000	0	0	0
SUBTRANS3	20 KV		0.0	0.00%	0.000	0.001	0.001	0	12	12
SUBTOT			2,201.2		16.500	0.001	16.501	57,222	12	57,234
PRIMARY LINES			9,018		24.229	0.484	24.714	75,841	4,242	80,083
SECONDARY LINES			3,607		7.326	0.000	7.326	24,216	0	24,216
SERVICES			3,971		4.277	0.379	4.656	12,899	3,322	16,221
TOTAL			20,494		89.402	2.413	91.815	298,736	21,135	319,872

SUMMARY OF TRANSFORMER INFORMATION

EXHIBIT 3

DESCRIPTION		KV VOLTAGE	CAPACITY MVA	NUMBER TRANSFMR	AVERAGE SIZE	LOADING %	MVA LOAD	MW LOSSES LOAD	MW LOSSES NO LOAD	MW LOSSES TOTAL	MWH LOSSES LOAD	MWH LOSSES NO LOAD	MWH LOSSES TOTAL
BULK STEP-UP		345	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
BULK - BULK			0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
BULK - TRANS1		161	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
BULK - TRANS2		115	3,037.0	11	276.1	30.38%	923	0.608	2.895	3.503	509	25,356	25,865
TRANS1 STEP-UP		161	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
TRANS1 - TRANS2		115	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
TRANS1-SUBTRANS1		66	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
TRANS1-SUBTRANS2		46	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
TRANS1-SUBTRANS3		20	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
TRANS2 STEP-UP		115	215.0	3	71.7	14.92%	32	0.050	0.192	0.242	173	1,679	1,852
TRANS2-SUBTRANS1		66	2,530.9	44	57.5	36.35%	920	1.475	2.778	4.253	5,959	24,337	30,296
TRANS2-SUBTRANS2		46	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
TRANS2-SUBTRANS3		20	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
SUBTRAN1 STEP-UP		66	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
SUBTRAN2 STEP-UP		46	0.0	0	0.0	0.00%	0	0.000	0.001	0.001	0	0	0
SUBTRAN3 STEP-UP		20	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
SUBTRAN1-SUBTRAN2		46	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
SUBTRAN1-SUBTRAN3		20	13.7	2	6.9	41.71%	6	0.016	0.024	0.040	55	206	262
SUBTRAN2-SUBTRAN3		20	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
DISTRIBUTION SUBSTATIONS													
TRANS1 -	161	12	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
TRANS1 -	161	4	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
TRANS1 -	161	1	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
TRANS2 -	115	12	950.0	39	24.4	39.98%	380	0.805	1.300	2.105	3,080	11,389	14,469
TRANS2 -	115	4	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
TRANS2 -	115	1	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
SUBTRAN1-	66	12	1,658.5	157	10.6	41.41%	687	1.886	2.576	4.462	7,056	22,565	29,621
SUBTRAN1-	66	4	80.5	16	5.0	31.40%	25	0.078	0.139	0.218	289	1,222	1,510
SUBTRAN1-	66	1	44.9	18	2.5	33.75%	15	0.049	0.087	0.136	164	758	922
SUBTRAN2-	46	12	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
SUBTRAN2-	46	4	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
SUBTRAN2-	46	1	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
SUBTRAN3-	20	12	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
SUBTRAN3-	20	4	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
SUBTRAN3-	20	1	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
PRIMARY - PRIMARY			12.4	9	1.4	21.89%	3	0.009	0.024	0.033	41	213	254
LINE TRANSFRMR			4,063.5	98,377	41.3	23.00%	935	2.428	12.412	14.840	5,046	108,733	113,778
			===========	===========	===========	===========		===========	===========	===========	===========	===========	===========
TOTAL			12,606	98,676				7.404	22.428	29.831	22,372	196,458	218,831

SUMMARY OF LOSSES DIAGRAM - DEMAND MODEL - SYSTEM PEAK 1148 2 MW



FROM HIGH VOLTAGE SYSTEM

EXHIBIT 4 PAGE 2 of 2

TOTAL 1 107 MVA 1 085 MW

TRANS1	TRANS2	SUBTRANS1	SUBTRANS2	SUBTRANS3
0 0 MVA	379 8 MVA	727 2 MVA	0 0 MVA	0 0 MVA
0 00%	34 31%	65 69%	0 00%	0 00%
161 KV	115 KV	66 KV	46 KV	20 KV

DISTRIBUTION SYSTEM LOAD

	PRIM1	PRIM2	PRIM3	PRIM1	PRIM2	PRIM3	PRIM1	PRIM2	PRIM3	PRIM1	PRIM2	PRIM3	PRIM1	PRIM2	PRIM3
VOLTAGE	12	4	1	12	4	1	12	4	1	12	4	1	12	4	1
LOAD MVA	0	0	0	380	0	0	687	25	15	0	0	0	0	0	0
% SYS TOT	0 00%	0 00%	0 00%	34 31%	0 00%	0 00%	62 04%	2 28%	1 37%	0 00%	0 00%	0 00%	0 00%	0 00%	0 00%
NOLD LOSS	0 000	0 000	0 000	1 300	0 000	0 000	2 576	0 139	0 087	0 000	0 000	0 000	0 000	0 000	0 000
LOAD LOSS	0 000	0 000	0 000	0 805	0 000	0 000	1 886	0 078	0 049	0 000	0 000	0 000	0 000	0 000	0 000
AVG SIZE	0 0	0 0	0 0	24 4	0 0	0 0	10 6	5 0	2 5	0 0	0 0	0 0	0 0	0 0	0 0
NUMBER	0	0	0	39	0	0	157	16	18	0	0	0	0	0	0
DIVERSITY RATIO	0 000	0 000	0 000	1 000	0 000	0 000	1 003	1 000	1 130	0 000	0 000	0 000	0 000	0 000	0 000

PRIMARY LINES

LOADING	1078 197	MW
@ SYS PF	1100 201	MVA
LOAD LOSS	24 229	MW
NOLD LOSS	0 484	MW
TOT LOSS	24 714	MW

PRIM/PRIM TRANSF

LOADING	2 709	MW
NOLD LOSS	0 024	MW
LOAD LOSS	0 009	MW
AVG SIZE	1 38	
NUMBER	9	

PRIM CUST LOADS

NO LINES CUST SUB	0 000	MW
	0 000	MVA
NO LINES CO SUB	0 000	MW
	0 000	MVA
PRIM WITH LINES	196 000	MW
	213 043	MVA

LINE TRANSFORMERS

LOADING	857 451	MW	MVA 949 363
NOLD LOSS	12 412	MW	
LOAD LOSS	2 426	MW	
AVG SIZE	41 3	KVA	
NUMBER	98377		

SECONDARY LINES

LOAD	332 237	MW
LOAD LOSS	7 326	MW
NOLD LOSS	0 000	MW
TOT LOSS	7 326	MW

NO SECONDARY LINES

LOAD 510 374 MW

SERVICES

LOAD	835 284	MW
LOAD LOSS	4 277	MW
NOLD LOSS	0 379	MW
TOT LOSS	4 656	MW

CUSTOMER SECONDARY LOAD

830 628 MW

SUMMARY of SALES and CALCULATED LOSSES

EXHIBIT 5

LOSS # AND LEVEL	MW LOAD	NO LOAD +	LOAD =	TOT LOSS	EXP FACTOR	CUM EXP FAC	MWH LOAD	NO LOAD +	LOAD =	TOT LOSS	EXP FACTOR	CUM EXP FAC
1 BULK XFMMR	0.0	0 00	0.00	0 00	0.000000	0 000000	0	0	0	0	0	0
2 BULK LINES	1,000.0	0 84	4.57	5.41	1.005439	1.005439	5,065,928	7,351	35,806	43,156	1.0085921	1.0085921
3 TRANS1 XFMR	0.0	0 00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.0000000	0.0000000
4 TRANS1 LINES	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.0000000	0 0000000
5 TRANS2TR1 SD	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.0000000	0.0000000
6 TRANS2BLK SD	904.2	2.89	0.61	3.50	1.003889	1.009349	4,831,517	25,356	509	25,865	1.0053822	1.0140206
7 TRANS2 LINES	1,285.6	0.90	32.55	33.45	1.026714	1.033465	7,733,504	7,888	112,883	120,770	1.0158643	1 0247626
TOTAL TRAN	1,285.6	4.63	37.73	42.36	1.034074	1.034074	7,733,504	40,594	149,198	189,792	1.0251590	1.0251590
8 STR1BLK SD												
9 STR1T1 SD	0.0	0.00	0.00	0.00	0.000000	0 000000	0	0	0	0	0.0000000	0.0000000
10 SRT1T2 SD	901.6	2.78	1.47	4.25	1.004739	1.038362	4,818,030	24,337	5,959	30,296	1.0063278	1 0312472
11 SUBTRANS1 LINES	901.6	0.00	16.50	16.50	1.018641	1.057719	4,818,030	0	57,222	57,222	1.0120194	1 0436421
12 STR2T1 SD	0.0	0.00	0.00	0.00	0.000000	0 000000	0	0	0	0	0.0000000	0.0000000
13 STR2T2 SD	0.0	0.00	0.00	0 00	0.000000	0.000000	0	0	0	0	0.0000000	0 0000000
14 STR2S1 SD	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.0000000	0 0000000
15 SUBTRANS2 LINES	0 0	0 00	0.00	0 00	0.000000	0 000000	0	0	0	0	0.0000000	0 0000000
16 STR3T1 SD	0.0	0 00	0.00	0 00	0.000000	0 000000	0	0	0	0	0.0000000	0 0000000
17 STR3T2 SD	0.0	0 00	0.00	0 00	0.000000	0 000000	0	0	0	0	0.0000000	0 0000000
18 STR3S1 SD	5.6	0 02	0.02	0 04	1.007173	1 065305	27,511	206	55	262	1.0095971	1 0536581
19 STR3S2 SD	0.0	0 00	0.00	0 00	0.000000	0 000000	0	0	0	0	0.0000000	0 0000000
20 SUBTRANS3 LINES	5 6	0 00	0.00	0 00	1.000246		27,511	12	0	12	1 0004396	
21 SUBTRANS TOTAL	907 3	2 80	17.99	20 80	1.023459		4,845,541	24,555	63,237	87,792	1.0184523	
22 TOT TRANS LOSS FAC	1,549.3	7.44	55.72	63.16	1.042497	1.042497	8,427,416	65,149	212,435	277,583	1.0340600	1.0340600
DISTRIBUTION SUBST												
TRANS1	0.0	0 00	0.00	0 00	0 000000	0 000000	0	0	0	0	0.0000000	0 0000000
TRANS2	372.2	1 30	0.80	2 10	1 005688	1 048427	1,958,190	11,389	3,080	14,469	1.0074440	1 0323910
SUBTR1	712.7	2 80	2.01	4 81	1.006802	1 049589	3,756,591	24,545	7,509	32,054	1.0086062	1 0526239
SUBTR2	0.0	0 00	0.00	0 00	0.000000	0 000000	0	0	0	0	0.0000000	0 0000000
SUBTR3	0.0	0 00	0.00	0 00	0.000000	0 000000	0	0	0	0	0.0000000	0 0000000
WEIGHTED AVERAGE	1,084 9	4 10	2.82	6 92	1 006420	1 049190	5,714,781	35,934	10,589	46,523	1.0082077	1 0425472
PRIMARY INTRCHNGE	0.0				0.000000		0				0 0000000	
PRIMARY LINES	1,078 2	0 48	24.24	24 72	1.023468	1 073812	5,668,559	4,242	75,882	80,124	1.0143374	1 0574947
LINE TRANSF	857.5	12 41	2.43	14 84	1.017613	1 092724	3,899,380	108,733	5,046	113,778	1.0300555	1 0892783
SECONDARY	842.6	0 00	7.33	7 33	1.008771	1 102308	3,785,602	0	24,216	24,216	1.0064380	1 0962911
SERVICES	835.3	0 38	4.28	4 66	1.005606	1 108488	3,761,386	3,322	12,899	16,221	1.0043312	1 1010394
		===========	===========	===========				===========	===========	===========		
TOTAL SYSTEM		24.82	96.81	121 62				217,380	341,066	558,446		

DEVELOPMENT of LOSS FACTORS EXHIBIT 6
UNADJUSTED
DEMAND

LOSS FACTOR LEVEL	CUSTOMER SALES MW a	CALC LOSS TO LEVEL b	SALES MW @ GEN c	CUM PEAK EXPANSION FACTORS d	1/d
BULK LINES	0.0	0.0	0.0	0.00000	0.00000
TRANS SUBS	0.0	0.0	0.0	0.00000	0.00000
TRANS LINES	0.0	0.0	0.0	0.00000	0.00000
SUBTRANS SUBS	0.0	0.0	0.0	0.00000	0.00000
TOTAL TRANS	14.8	0.6	15.4	1.04250	0.95924
PRIM SUBS	0.0	0.0	0.0	0.00000	0.00000
PRIM LINES	196.0	14.5	210.5	1.07381	0.93126
SECONDARY	830.6	90.1	920.7	1.10849	0.90213
TOTALS	1,041.4	105.2	1,146.6		

DEVELOPMENT of LOSS FACTORS
UNADJUSTED
ENERGY

LOSS FACTOR LEVEL	CUSTOMER SALES MWH a	CALC LOSS TO LEVEL b	SALES MWH @ GEN c	CUM ANNUAL EXPANSION FACTORS d	1/d
BULK LINES	0	0	0	0.00000	0.00000
TRANS SUBS	0	0	0	0.00000	0.00000
TRANS LINES	0	0	0	0.00000	0.00000
SUBTRANS SUBS	0	0	0	0.00000	0.00000
TOTAL TRANS	179,914	6,128	186,042	1.03406	0.96706
PRIM SUBS	0	0	0	0.00000	0.00000
PRIM LINES	1,689,055	97,112	1,786,167	1.05749	0.94563
SECONDARY	3,745,165	378,409	4,123,574	1.10104	0.90823
TOTALS	5,614,134	481,649	6,095,783		

ESTIMATED VALUES AT GENERATION

LOSS FACTOR AT VOLTAGE LEVEL	MW	MWH
BULK LINES	0.00	0
TRANS SUBS	0.00	0
TRANS LINES	0.00	0
SUBTRANS SUBS	0.00	0
TOTAL TRANS	15.43	186,042
PRIM SUBS	0.00	0
PRIM LINES	210.47	1,786,167
SECONDARY	920.74	4,123,574
SUBTOTAL	1,146.64	6,095,783
ACTUAL ENERGY	1,148.20	6,091,890
MISSMATCH	(1.56)	3,893
% MISSMATCH	-0.14%	0.06%

DEVELOPMENT of LOSS FACTORS
ADJUSTED
DEMAND

EXHIBIT 7

LOSS FACTOR LEVEL	CUSTOMER SALES MW a	SALES ADJUST b	CALC LOSS TO LEVEL c	SALES MW @ GEN d	CUM PEAK EXPANSION FACTORS e	f=1/e
BULK LINES	0.0	0.0	0.0	0.0	0.00000	0.00000
TRANS SUBS	0.0	0.0	0.0	0.0	0.00000	0.00000
TRANS LINES	0.0	0.0	0.0	0.0	0.00000	0.00000
SUBTRANS SUBS	0.0	0.0	0.0	0.0	0.00000	0.00000
TOTAL TRANS	14.8	0.0	0.6	15.4	1.04250	0.95924
PRIM SUBS	0.0	0.0	0.0	0.0	0.00000	0.00000
PRIM LINES	196.0	0.0	14.6	210.6	1.07461	0.93057
SECONDARY	830.6	0.0	91.5	922.1	1.11018	0.90075
			106.8			
TOTALS	1,041.4	0.0	106.8	1,148.2	1.10252 <COMPOSITE	

DEVELOPMENT of LOSS FACTORS
ADJUSTED
ENERGY

LOSS FACTOR LEVEL	CUSTOMER SALES MWH a	SALES ADJUST b	CALC LOSS TO LEVEL c	SALES MWH @ GEN d	CUM ANNUAL EXPANSION FACTORS e	f=1/e
BULK LINES	0	0	0	0	0.00000	0.00000
TRANS SUBS	0	0	0	0	0.00000	0.00000
TRANS LINES	0	0	0	0	0.00000	0.00000
SUBTRANS SUBS	0	0	0	0	0.00000	0.00000
TOTAL TRANS	179,914	0	6,128	186,042	1.03406	0.96706
PRIM SUBS	0	0	0	0	0.00000	0.00000
PRIM LINES	1,689,055	0	96,581	1,785,636	1.05718	0.94591
SECONDARY	3,745,165	0	375,047	4,120,212	1.10014	0.90897
			477,756			
TOTALS	5,614,134	0	477,756	6,091,890	1.08510 <COMPOSITE	

ESTIMATED VALUES AT GENERATION

LOSS FACTOR AT VOLTAGE LEVEL	MW	MWH
BULK LINES	0.00	0
TRANS SUBS	0.00	0
TRANS LINES	0.00	0
SUBTRANS SUBS	0.00	0
TOTAL TRANS	15.43	186,042
PRIM SUBS	0.00	0
PRIM LINES	210.62	1,785,636
SECONDARY	922.15	4,120,212
	1,148.20	6,091,890
ACTUAL ENERGY	1,148.20	6,091,890
MISSMATCH	0.00	0
% MISSMATCH	0.00%	0.00%

Adjusted Losses and Loss Factors by Facility EXHIBIT 8

Unadjusted Losses by Segment

		MW	Unadjusted	MWH	Unadjusted	
Service Drop Losses		4 66	4 40	16,221	15,096	
Secondary Losses		7.33	6.93	24,216	22,536	
Line Transformer Losses		14.84	14.03	113,778	105,887	
Primary Line Losses		24 72	23 37	80,124	74,567	
Distribution Substation Losses		6 92	6 54	46,523	43,296	
Transmission System Losses		49.94	49.94	220,266	220,266	
Total		108.40	105.21	501,129	481,649	

Mismatch Allocation by Segment

		MW		MWH		
Service Drop Losses		-0 12		225		
Secondary Losses		-0 20		336		
Line Transformer Losses		-0.40		1,577		
Primary Line Losses		-0.66		1,110		
Distribution Substation Losses		-0 19		645		
Transmission System Losses	0	0.00		0		
Total		-1.56		3,893		

Adjusted Losses by Segment

		MW	% of Total	MWH	% of Total	
Service Drop Losses		4.53	4.2%	14,871	3.1%	
Secondary Losses		7 12	6.7%	22,201	4.6%	
Line Transformer Losses		14 43	13.5%	104,310	21.8%	
Primary Line Losses		24.03	22.5%	73,456	15.4%	
Distribution Substation Losses		6.73	6.3%	42,652	8.9%	
Transmission System Losses		49 94	46.8%	220,266	46.1%	
Total		106 77	100.0%	477,756	100 0%	

Loss Factors by Segment

		MW		MWH		
Retail Sales from Service Drops		830.63		3,745,165		
Adjusted Service Drop Losses		4.53		14,871		
Input to Service Drops		835 15		3,760,036		
Service Drop Loss Factor		**1.00545**		**1.00397**		
Output from Secondary		835.15		3,760,036		
Adjusted Secondary Losses		7 12		22,201		
Input to Secondary		842 28		3,782,237		
Secondary Conductor Loss Factor		**1.00853**		**1.00590**		
Output from Line Transformers		842 28		3,782,237		
Adjusted Line Transformer Losses		14.43		104,310		
Input to Line Transformers		856.70		3,886,547		
Line Transformer Loss Factor		**1.01713**		**1.02758**		
Retail Sales from Primary		196.00		1,689,055		
Req Whls Sales from Primary		0 00		0		
Input to Line Transformers		856.70		3,886,547		
Output from Primary Lines		1052.70		5,575,602		
Adjusted Primary Line Losses		24.03		73,456		
Input to Primary Lines		1076 73		5,649,058		
Primary Line Loss Factor		**1.02283**		**1.01317**		
Output from Distribution Substations		1076.73		5,649,058		
Req. Whls Sales from Substations		0 00		0		
Retail Sales from Substations		0.00		0		
Adjusted Distribution Substation Losses		6.73		42,652		
Input to Distribution Substations		1083.46		5,691,710		
Distribution Substation Loss Factor		**1.00625**		**1.00755**		
Retail Sales at from SubTransmission		14 80		179,914		
Req Whls Sales from SubTransmission		0 00		0		
Non-Req. Whls Sales from SubTransmission		0.00		0		
Third Party Wheeling Losses		0.00		0		
Input to Distribution Substations		1083.46		5,691,710		
Output from SubTransmission		1098.26		5,871,624		5,871,624
Adjusted SubTransmission System Losses		49.94		220,266		220,266
Input to Transmission		1148.20		6,091,890		6,091,890
TotTransmission System Loss Factor		**1.04260**		**1.03406**		1 03751

DEMAND MW

SUMMARY OF LOSSES AND LOSS FACTORS BY DELIVERY VOLTAGE

	SERVICE LEVEL		SALES MW	LOSSES	SECONDARY	PRIMARY	SUBSTATION	PRIM&SUBS COMPOSITE	TRANSMISSION
1	**SERVICES**								
2	SALES		830 6		830 6				
3	LOSSES			4 5	4 5				
4	INPUT				835 2				
5	**EXPANSION FACTOR**	**1.00545**							
6	**SECONDARY**								
7	SALES								
8	LOSSES			7 1	7 1				
9	INPUT				842 3				
10	**EXPANSION FACTOR**	**1.00853**							
11	**LINE TRANSFORMER**								
12	SALES								
13	LOSSES			14 4	14 4				
14	INPUT				856 7				
15	**EXPANSION FACTOR**	**1.01713**							
16	**PRIMARY**								
17	SECONDARY				856 7				
18	SALES		196 0			196 0			
19	LOSSES			24 0	19 6	4 5			
20	INPUT								
21	**EXPANSION FACTOR**	**1.02283**							
22	**SUBSTATION**								
23	PRIMARY				876 3	200 5			
24	SALES		0 0				0 0		
25	LOSSES			6 7	5 5	1 3	0 0		
26	INPUT				881 7	201 7	0 0		
27	**EXPANSION FACTOR**	1.00626							
28	**SUB-TRANSMISSION**								
29	DISTRIBUTION SUBS								
30	SALES								
31	LOSSES								
32	INPUT								
33	**EXPANSION FACTOR**								
34	**TRANSMISSION**								
35	SUBTRANSMISSION								
36	DISTRIBUTION SUBS				881 7	201 7	0 0		
37	SALES		14 8						14 8
38	LOSSES			49 9	37 5	8 6	0 0		0 6
39	INPUT				919 2	210 3	0 0		15 4
40	**EXPANSION FACTOR**	1.04250							
41	**TOTALS** LOSSES			106 8	88 6	14 3	0 0		0 6
42	% OF TOTAL			100%	82 96%	13 39%	0 00%		0 59%
43	SALES		1,041 4		830 6	196 0	0 0		14 8
44	% OF TOTAL		100 00%		79 76%	18 82%	0 00%		1 42%
45	INPUT		1,144 9		919 2	210 3	0 0		15 4
46	**CUMMULATIVE EXPANSION LOSS FACTORS** (from meter to system input)				1.10664	1.07296	NA		1.04250

ENERGY MWH — **SUMMARY OF LOSSES AND LOSS FACTORS BY DELIVERY VOLTAGE**

	SERVICE LEVEL		SALES	LOSSES	SECONDARY	PRIMARY	SUBSTATION	PRIM&SUBS COMPOSITE	TRANSMISSION
1	**SERVICES**								
2	SALES		3,745 165		3,745 165				
3	LOSSES			14 871	14,871				
4	INPUT				3,760 036				
5	**EXPANSION FACTOR**	1.00397							
6	**SECONDARY**								
7	SALES								
8	LOSSES			22 201	22 201				
9	INPUT				3,782 237				
10	**EXPANSION FACTOR**	1.00590							
11	**LINE TRANSFORMER**								
12	SALES								
13	LOSSES			104 310	104,310				
14	INPUT				3,886 547				
15	**EXPANSION FACTOR**	1.02758							
16	**PRIMARY**								
17	SECONDARY				3,886 547				
18	SALES		1,689,055			1 689,055			
19	LOSSES			73,456	51 204	22,253			
20	INPUT								
21	**EXPANSION FACTOR**	1.01317							
22	**SUBSTATION**								
23	PRIMARY				3,937,751	1 711,308			
24	SALES		0				0		
25	LOSSES			42,652	29,731	12,921	0		
26	INPUT				3,967,482	1,724,228	0		
27	**EXPANSION FACTOR**	1.00755							
28	**SUB-TRANSMISSION**								
29	DISTRIBUTION SUBS								
30	SALES								
31	LOSSES								
32	INPUT								
33	**EXPANSION FACTOR**								
34	**TRANSMISSION**								
35	SUBTRANSMISSION								
36	DISTRIBUTION SUBS				3,967,482	1 724,228	0		
37	SALES		179 914						179 914
38	LOSSES			220 266	135,953	58,887	0		6 128
39	INPUT				4,103,434	1 783,116	0		186,042
40	**EXPANSION FACTOR**	1.03406			820	160			
41	**TOTALS** LOSSES			477 756	358,269	94,061	0		6,128
42	% OF TOTAL			100%	74 99%	19 69%	0 00%		1 28%
43	SALES		5,614 134		3,745.165	1 689,055	0		179 914
44	% OF TOTAL		100 00%		66 71%	30 09%	0 00%		3 20%
45	INPUT		6,072 592		4,103.434	1 783,116	0		186 042
46	**CUMMULATIVE EXPANSION LOSS FACTORS** (from meter to system input)				1.09566	1 06569	NA		1.03406

TCC and TNC | **DEVELOPMENT of LOSS FACTORS** | **EXHIBIT 10**
COMPOSITE | **ADJUSTED** **EXHIBIT 7** | PAGE 1 OF 2
LOSS FACTORS | **DEMAND**

LOSS FACTOR LEVEL	CUSTOMER SALES MW	SALES ADJUST	CALC LOSS TO LEVEL	SALES MW @ GEN	CUM PEAK FACTORS	EXPANTION
	a	b	c	d	e	f=1/e
BULK LINES	0.0	0.0	0.0	0.0	0.00000	0
TRANS SUBS	0.0	0.0	0.0	0.0	0.00000	0
TRANS LINES	0.0	0.0	0.0	0.0	0.00000	0
SUBTRANS SUBS	0.0	0.0	0.0	0.0	0.00000	0
TOTAL TRANS	627.1	0.0	14.8	641.9	1.02353	0.97824
PRIM SUBS	0.0	0.0	0.0	0.0	0.00000	0
PRIM LINES	571.3	0.0	38.6	609.9	1.06761	0.94061
SECONDARY	4,683.8	0.0	432.0	5,115.7	1.09223	0.91849
TOTALS	5,882.2	0.0	485.3	6,367.5	1.08251	<COMPOSITE

DEVELOPMENT of LOSS FACTORS
ADJUSTED
ENERGY

LOSS FACTOR LEVEL	CUSTOMER SALES MWH	SALES **ADJUST**	CALC LOSS TO LEVEL	SALES MWH @ GEN	CUM ANNU FACTORS	EXPANTION
	a	b	c	d	e	f=1/e
BULK LINES	0	0	0	0	0.00000	0.00000
TRANS SUBS	0	0	0	0	0.00000	0.00000
TRANS LINES	0	0	0	0	0.00000	0.00000
SUBTRANS SUBS	0	0	0	0	0.00000	0.00000
TOTAL TRANS	5,751,071	0	100,343	5,851,414	1.01745	0.98285
PRIM SUBS	0	0	0	0	0.00000	0.00000
PRIM LINES	4,268,133	0	216,821	4,484,954	1.05080	0.95166
SECONDARY	21,719,495	0	1,740,690	23,460,185	1.08014	0.92580
TOTAL	31,738,699	0	2,057,854	33,796,553	1.06484	<COMPOSITE

TCC

DEVELOPMENT of LOSS FACTORS
ADJUSTED **EXHIBIT 7**
DEMAND

LOSS FACTOR LEVEL	CUSTOMER SALES MW a	SALES ADJUST b	CALC LOSS TO LEVEL c	SALES MW @ GEN d	CUM PEAK FACTORS e	EXPANTION f=1/e
BULK LINES	0.0	0	0	0.0	0.00000	0
TRANS SUBS	0.0	0	0	0.0	0.00000	0
TRANS LINES	0.0	0	0	0.0	0.00000	0
SUBTRANS SUBS	0.0	0.0	0.0	0.0	0.00000	0
TOTAL TRANS	612.3	0.0	14.1	626.4	1.02307	0.97824
PRIM SUBS	0.0	0.0	0.0	0.0	0.00000	0
PRIM LINES	375.3	0.0	24.0	399.3	1.06395	0.94061
SECONDARY	3,853.1	0.0	340.4	4,193.6	1.08836	0.91849
TOTALS	4,840.7	0.0	378.6	5,219.3	1.07821	<COMPOSITE

DEVELOPMENT of LOSS FACTORS
ADJUSTED
ENERGY

LOSS FACTOR LEVEL	CUSTOMER SALES MWH a	SALES ADJUST b	CALC LOSS TO LEVEL c	SALES MWH @ GEN d	CUM ANNU. FACTORS e	EXPANTION f=1/e
BULK LINES	0	0	0	0	0.00000	0.00000
TRANS SUBS	0	0	0	0	0.00000	0.00000
TRANS LINES	0	0	0	0	0.00000	0.00000
SUBTRANS SUBS	0	0	0	0	0.00000	0.00000
TOTAL TRANS	5,571,157	0	94,215	5,665,372	1.01691	0.98337
PRIM SUBS	0	0	0	0	0.00000	0.00000
PRIM LINES	2,579,078	0	120,240	2,699,318	1.04662	0.95546
SECONDARY	17,974,330	0	1,365,643	19,339,973	1.07598	0.92939
TOTAL	26,124,565	0	1,580,098	27,704,663	1.06048	<COMPOSITE

TNC

DEVELOPMENT of LOSS FACTORS
ADJUSTED **EXHIBIT 7**
DEMAND

LOSS FACTOR LEVEL	CUSTOMER SALES MW a	SALES ADJUST b	CALC LOSS TO LEVEL c	SALES MW @ GEN d	CUM PEAK FACTORS e	EXPANTION f=1/e
BULK LINES	0.0	0	0	0.0	0.00000	0.00000
TRANS SUBS	0.0	0	0	0.0	0.00000	0.00000
TRANS LINES	0.0	0	0	0.0	0.00000	0.00000
SUBTRANS SUBS	0.0	0	0	0.0	0.00000	0.00000
TOTAL TRANS	14.8	0.0	0.6	15.4	1.04250	0.95924
PRIM SUBS	0.0	0.0	0.0	0.0	0.00000	0.00000
PRIM LINES	196.0	0.0	14.6	210.6	1.07461	0.93057
SECONDARY	830.6	0.0	91.5	922.1	1.11018	0.90075
TOTALS	1,041.4	0.0	106.8	1,148.2	1.10252	<COMPOSITE

DEVELOPMENT of LOSS FACTORS
ADJUSTED
ENERGY

LOSS FACTOR LEVEL	CUSTOMER SALES MWH a	SALES ADJUST b	CALC LOSS TO LEVEL c	SALES MWH @ GEN d	CUM ANNU. FACTORS e	EXPANTION f=1/e
BULK LINES	0	0	0	0	0.00000	0.00000
TRANS SUBS	0	0	0	0	0.00000	0.00000
TRANS LINES	0	0	0	0	0.00000	0.00000
SUBTRANS SUBS	0	0	0	0	0.00000	0.00000
TOTAL TRANS	179,914	0	6,128	186,042	1.03406	0.96706
PRIM SUBS	0	0	0	0	0.00000	0.00000
PRIM LINES	1,689,055	0	96,581	1,785,636	1.05718	0.94591
SECONDARY	3,745,165	0	375,047	4,120,212	1.10014	0.90897
TOTAL	5,614,134	0	477,756	6,091,890	1.08510	<COMPOSITE

Appendix B

Discussion of Hoebel Coefficient

COMMENTS ON THE HOEBEL COEFFICIENT

The Hoebel coefficient represents an established industry standard relationship between peak losses and average losses and is used in a loss study to estimate energy losses from peak demand losses. H. F. Hoebel described this relationship in his article, "Cost of Electric Distribution Losses," Electric Light and Power, March 15, 1959. A copy of this article is attached.

Within any loss evaluation study, peak demand losses can readily be calculated given equipment resistance and approximate loading. Energy losses, however, are much more difficult to determine given their time-varying nature. This difficulty can be reduced by the use of an equation which relates peak load losses (demand) to average losses (energy). Once the relationship between peak and average losses is known, average losses can be estimated from the known peak load losses.

Within the electric utility industry, the relationship between peak and average losses is known as the loss factor. For definitional purposes, loss factor is the ratio of the average power loss to the peak load power loss, during a specified period of time. This relationship is expressed mathematically as follows:

(1) $F_{LS} \cong A_{LS} \div P_{LS}$

where:
F_{LS} = Loss Factor
A_{LS} = Average Losses
P_{LS} = Peak Losses

The loss factor provides an estimate of the degree to which the load loss is maintained throughout the period in which the loss is being considered. In other words, loss factor is the ratio of the actual kWh losses incurred to the kWh losses which would have occurred if full load had continued throughout the period under study.

Examining the loss factor expression in light of a similar expression for load factor indicates a high degree of similarity. The mathematical expression for load factor is as follows:

(2) $F_{LD} \cong A_{LD} \div P_{LD}$

where:
F_{LD} = Load Factor
A_{LD} = Average Load
P_{LD} = Peak Load

This load factor result provides an estimate of the degree to which the load loss is maintained throughout the period in which the load is being considered. Because of the similarities in definition, the loss factor is sometimes called the "load factor of losses." While the definitions are similar, a strict equating of the two factors cannot be made. There does exist, however, a relationship between these two factors which is dependent upon the shape of the load duration curve. Since resistive losses vary as the square of the load, it can be shown mathematically that the loss factor can vary between the extreme limits of load factor and load factor squared. The relationship between load factor and loss factor has become an industry standard and is as follows:

$$(3)\ F_{LS} \cong H^*F_{LD}^2 + (1-H)^*F_{LD}$$

where: F_{LS} = Loss Factor
F_{LD} = Load Factor
H = Hoebel Coefficient

As noted in the attached article, the suggested value for H (the Hoebel coefficient) is 0.7. The exact value of H will vary as a function of the shape of the utility's load duration curve. In recent years, values of H have been computed directly for a number of utilities based on EEI load data. It appears on this basis, the suggested value of 0.7 should be considered a lower bound and that values approaching unity may be considered a reasonable upper bound. Based on experience, values of H have ranged from approximately 0.85 to 0.95. The standard default value of 0.9 is generally used.

Inserting the Hoebel coefficient estimate gives the following loss factor relationship using Equation (3):

$$(4)\ F_{LS} \cong 0.90^*F_{LD}^2 + 0.10^*F_{LD}$$

Once the Hoebel constant has been estimated and the load factor and peak losses associated with a piece of equipment have been estimated, one can calculate the average, or energy losses as follows:

$$(5)\ A_{LS} \cong P_{LS} * [H^*F_{LD}^2 + (1-H)^*F_{LD}]$$

where: A_{LS} = Average Losses
P_{LS} = Peak Losses
H = Hoebel Coefficient
F_{LD} = Load Factor

Loss studies use this equation to calculate energy losses at each major voltage level in the analysis.