Assessment of Transmission and Distribution Losses in New York

PID071178 (NYSERDA 15464)

Final Report, November, 2012

Assessment of Transmission and Distribution Losses in New York State

Final Report

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EXECUTIVE SUMMARY

This report presents industry practices for loss calculations; examines industry trends on loss mitigation, including emerging trends; and explores techniques to determine the cost effectiveness of loss reduction measures.

In 2008, the State of New York Public Service Commission (PSC) established an Energy Efficiency Portfolio Standard for the state and adopted the goal of reducing New York's electricity usage by 15 percent by 2015 (15 x 15).[1] The PSC required the utilities to submit reports within six months of the order "identifying measures to reduce system losses and/or optimize system operations."[2]

The New York State Energy Research and Development Authority (NYSERDA); Electric Power Research Institute, Inc. (EPRI); and SAIC Energy, Environment & Infrastructure, LLC (SAIC) worked together with eight participating New York utilities and the New York Independent System Operator (NYISO) to identify practices and methodologies for performing evaluations of losses in electric systems and reduction studies. This report reviewed:

- Industry practices and methods used by the New York utilities to calculate losses in electric transmission and distribution (T&D) systems
- Measures to reduce system losses
- The effect of reactive power tariffs on electric losses

Results and Findings

Losses in electric transmission and distribution systems in the service territories of the participating New York utilities ranged from 1.5 to 5.8 percent for transmission losses and from 1.9 to 4.6 percent for distribution losses based on utility loss studies presented to the PSC in 2008 and 2009. These are comparable to other reported electric utility losses in the United States as reported by EPRI's Transmission Efficiency Initiative Study[3] and EPRI's Green Circuits Study[4].

Analysis confirms that New York utilities are using normal industry practices in calculating system losses and that there is not a single best practice that can be followed by every utility.

[1] PSC, Case 07-M-0548, "Proceedings on Motion of the Commission Regarding an Energy Efficiency Portfolio Standard," Order dated June 23, 2008.
[2] PSC, Case 08-E-0751, "Proceedings on Motion of the Commission to Identify the Sources of Electric System Losses and the Means of Reducing Them," Order dated July 17, 2008.
[3] *Transmission Efficiency Initiative*, EPRI, Palo Alto, CA. 2009. 1017894.
[4] *Green Circuits: Distribution Efficiency Case Studies*, EPRI, Palo Alto, CA. 2011. 1023518.

Table ES-1 presents options for calculating losses that might benefit utilities in performing future loss studies, gaining precision in calculations, and evaluating losses across the state cohesively.

Table ES-1
Noteworthy Industry Practices

Approach	Benefit	Requirements and Costs
Separate losses into technical and non-technical categories, and identify the cause and type of losses.	Target specific areas of loss contribution; develop appropriate strategies to mitigate losses; Document energy savings (in more specific areas) so that they can be properly credited for energy efficiency claims.	Adjustment in reporting of categories. Additional calculation methods, data, and/or metering may be required.
Install metering down to the distribution feeder level that captures kW, kVAR, kWh, kVARh.	Provide the necessary information to validate models and assumptions and help identify target areas for loss improvements. Gain precision in loss calculations by using actual metered data over assumptions and in calculating load and loss factors.	Adjustments in calculation methods in eliminating some assumptions and using actual metered data. Additional metering and/or updates to current metering technologies in use.
Move towards hourly transmission load flows or evaluate multiple load levels for various time periods (typically seasonal) in calculating transmission losses.	This type of modeling can provide a better representation of operating conditions that occur at different load levels and times of year. Gain precision in loss calculations.	May require updates to software, additional modeling of system components, additional metering.
Obtain more detailed system information (such as using a GIS/mapping system for identifying primary and/or secondary facilities).	Aides in reducing assumptions for loss calculations and in developing more detailed engineering models. Aides in identifying specific areas that will benefit from loss reduction where sampling methodology cannot accomplish this. Gain precision in loss calculations.	May require updates to software; additional effort in collecting system facility information if not already recorded. Additional expenses for collecting and maintaining system data.

Based on the work performed by the New York utilities, EPRI, and SAIC, as well as reviews of other industry studies, electric losses can be reduced by system improvements both on the transmission and distribution systems. Generic or case-specific cost/benefit analysis is required to justify required expenditure for these system improvements.

For transmission systems:

1. Optimization of existing controls for transformer taps, generator voltages, and switched shunt capacitor banks reduces current flow and minimizes losses.
2. Addition of shunt capacitor banks, fixed and switched, at points on the system closest to the reactive load source reduces current flow and minimizes losses.

For distribution systems:

3. Phase balancing reduces line and neutral conductor losses.
4. Distribution capacitor banks on the feeders to improve the feeder power factor reduces line losses.

5. Capacitor banks at or near the substation improve the station power factor caused by the substation power transformer VAR requirement, measured at the high side of the power transformer and reduce load losses in the substation transformer.
6. Use of life-cycle evaluation for equipment sizing (initial installation of distribution transformers and conductors) reduces transformer core and coil losses.

Not traditionally considered part of methods to reduce transmission and distribution losses, conservation voltage reduction (CVR) has shown in recent studies that reducing voltage can reduce demand and energy consumption without impact to customers. Voltage optimization (VO), which is a technique that first "tunes" the distribution system by implementing system improvements and then applies voltage reduction, increases the amount that the voltage can be reduced for most feeders, thereby reducing energy consumption, and can reduce losses by two to four times as compared to just lowering the voltage. The loss reduction comes from the no-load losses in the distribution transformers and from implementing system improvements to tune the distribution system, in addition to the minor reduction in line losses from reducing the energy consumption of end-use loads. Voltage optimization is not strictly T&D efficiency, but many of the same approaches to analyzing losses and T&D efficiency apply to voltage optimization. It has the potential for much larger energy savings than loss reduction.

Utilities can identify areas of the electric system that might have a higher potential for loss reduction and can perform specific analysis for these systems to determine whether system improvements can be cost-effective in reducing losses. Approaches to calculating the cost of losses and performing an economic evaluation of efficiency improvements are reviewed in this report.

From the review of reactive power tariffs, the participating New York utilities are incorporating provisions for reactive demand similar to other utilities across the country. Documentation and feedback on the impact of reactive power charges to utility customers are sparse and inconsistent in the industry. Some challenges identified in the industry and for the New York utilities include:

- Rates in place at several utilities in the industry are not applied consistently or are made so transparent that it is difficult to be able to determine whether the rate structure design is actually motivating customers to perform corrective actions.
- Choosing a requirement for an optimal reactive demand level can be challenging. There are other unique challenges in dealing with real-time control of reactive power resources such that having a single requirement would not produce optimal solutions at every point in the system.
- The penalties at several utilities in the industry may not be steep enough to motivate the applicable customers to take action.

Industry research demonstrates that the efficiency of the power-delivery system can be improved. If the main criterion for economic justification is the marginal cost of energy, the research tends to show that many initiatives to reduce losses cannot be cost-justified. If ancillary benefits such as carbon credits or power quality impacts are considered, project economics may change. For targeted areas, loss reduction can often be economically justified by implementing changes in the way that the system is operated—such as voltage set points, capacitor settings, and switching—and cost-justified capital investment that can reduce losses in the electric grid.

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1
INTRODUCTION

Electric utilities face pressure, either through competitive or regulatory forces, to operate systems as efficiently as possible. One approach is to make the electric grid more efficient by reducing the energy consumed by the grid itself in the form of electrical losses. The goal of this report is to help the New York utilities develop individual approaches to cost effectively reduce electric losses in a way that will benefit the general public of New York State.

Most efficiency improvements targeting loss reduction are evaluated on a case-by-case basis. Many loss-reduction techniques are not cost-effective based on loss reduction alone, such as reconductoring existing facilities; however, techniques such as increasing the conductor to the next larger size for new projects or when rebuilding can sometimes be justified. This type of policy would likely require utilities to modify design and construction standards in order to be implemented consistently throughout the utility. Considering losses as well as the cost of total ownership over time when system upgrades or improvements are evaluated or implemented can be used as a tool to increase efficiency.

Differences in losses between utilities are normal, even if consistent methodologies and categorization are used. Losses in transmission and distribution systems may be different between utilities due to physical and operating differences, such as different voltage levels, feeder lengths, loading patterns, and conductor sizing.

Figure 1-1 shows summaries from an EPRI study of study that included findings from 42 circuits that used detailed system models, and in some cases the system model extended to each customer meter. [2] Losses were calculated using hourly resolution from metered data.

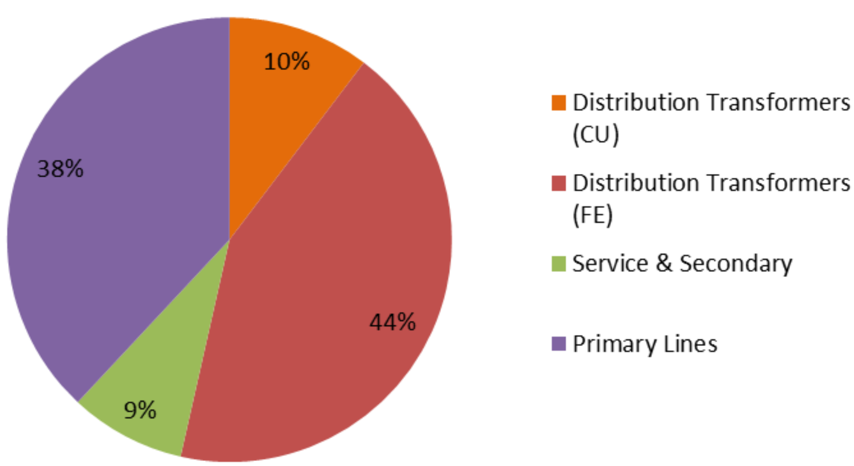


Figure 1-1
Breakdown of Distribution Losses – EPRI Study

Specific loss studies are necessary in order to identify and mitigate system losses. There will always be differences in loss values between utilities and within utilities due to technical and operational conditions. Specific loss studies are necessary when determining which loss-reduction strategies will be effective for a given distribution system.

The PSC issued an order effective June 23, 2008, for establishing an energy efficiency portfolio standard and adopted the goal of reducing New York's electricity usage by 15 percent by 2015 (the "15 x 15" goal). To move toward reaching the goal, the PSC order established a separate proceeding to examine the issue of system losses and directed the New York utilities to submit reports within six months "identifying measures to reduce system losses and/or optimize system operations."

The utilities were directed to identify all major sources of transmission and distribution losses, as well as include an analysis of specific programs and measures to mitigate those losses. The utilities were also directed to provide a review of reactive power provisions (existing and proposed) contained in their tariffs. The PSC order also directed the New York utilities to work with the NYISO to examine loss reduction from the use of optimal power flow technology on the bulk electric system.

As required, the New York electric utilities provided loss studies and proposed loss mitigation and reactive power tariffs to the PSC in late 2008/early 2009. In addition, the NYISO contracted ABB, Inc., to perform an optimal power flow study that identified mitigation techniques for loss reduction for the transmission grid. The reviews of the loss studies confirm that New York utilities are using standard industry practices in calculating system losses and that there is not a single best practice that can be followed by all utilities.

This study reviewed industry research and documents submitted to the PSC to identify the various methodologies used to calculate and identify transmission and distribution losses. The full loss studies from the participating utilities were evaluated. Also, submittals to the PSC for the June 23, 2008 order for "identifying measures to reduce system losses and/or optimize system operations" were evaluated. Interviews with each utility were conducted to gain a better understanding of the calculation methods and measures to mitigate loss noted in the submittals to the PSC. A collaborative work session with eight New York utilities, the PSC, NYSERDA, and the EPRI team was conducted in December 2011 to discuss current practices for conducting loss studies and assess common methodologies for performing future loss studies and address loss-reduction techniques.

The study relied heavily on the participating New York State utilities, including: Consolidated Edison, National Grid, New York State Electric and Gas, Rochester Gas and Electric, Central Hudson Gas and Electric, Orange and Rockland, and Long Island Power Authority, as well as the NYISO and the New York Power Authority.

The methods used by the participating utilities to calculate electric transmission and distribution (T&D) system losses, including estimations and calculation methods and a summary of the loss statistics, are presented. The purpose of identifying these methods is to gain a better understanding of the results of the loss studies and help improve the effort required by utilities in performing future loss studies. The report also describes strategies used by utilities to reduce system losses and the impact of new technology on electric system losses. Results of case studies are presented for several loss-mitigation strategies. Lastly, the report summarizes reactive power tariff provisions implemented by the participating utilities and other utilities to improve power factor and reduce losses.

2
TRANSMISSION LOSS CALCULATION METHODOLOGY

This section summarizes the loss calculations and methodologies for calculating transmission losses described in the loss studies provided by participating utilities. Loss studies from the participating utilities were reviewed, and telephone interviews were conducted with each utility to discuss the methodologies and loss findings included in their loss studies in more detail.

The percent losses of total transmission power requirements varied among utilities. The likely causes of the variations are the categorization of losses, differences in the number of load levels evaluated, differences in the age of facilities and voltage classes, and differences in the methodologies used to calculate losses. There is not a uniformly defined approach across the industry because each utility's electrical system is unique and the availability of information and data varies from utility to utility. Different trusted methodologies have been developed over the years to calculate losses based on the information that is available to each utility, which allows them to arrive at valid results.

Summary of Transmission Losses and Calculation Methodologies

Statistics for energy losses are summarized as reported by the participating utilities (see Table 2-1). Annual energy losses for the transmission systems ranged from 1.7 percent to 6.5 percent. The transmission losses as a percent of the total system losses ranged from 25.6 percent to 66.3 percent, excluding Utility D, which is a transmission-only utility (the transmission losses for this utility are therefore 100 percent of total system losses).

Table 2-1
Breakdown of Transmission Losses by Utility

Electric System Losses (Annual Energy Losses)		
Utility	**Total Transmission**	**% of Total System Losses**
A	2.93%	42.9%
B	1.70%	29.5%
C	1.75%	26.4%
D(*)	3.00%	100.0%
E	5.89%	56.4%
F	1.90%	50.0%
G	6.50%	66.3%
H	1.75%	25.6%
Average	3.18%	50.34%
Std. Dev.	1.94%	24.59%

*Transmission-only utility. Only peak demand losses were reported for Utility D.

A 2008 EPRI study[5] on system losses presented statistics for a sample of U.S. utilities. That study indicated an average transmission loss equal to 2.60 percent, with a standard deviation equal to 1.14 percent. On average, the transmission losses reported by the New York utilities are consistent with the system losses reported by other U.S. utilities, although there is a significant variation in results among the participating utilities. Two of the utilities reported losses that were significantly greater than the average for the participating utilities.

Transmission voltage levels for the participating utilities ranged from 34.5 kV to 765 kV for the participating utilities. Annual energy losses were determined from the calculated peak or various load level losses and load factors. In some cases, load factors were developed for each voltage class.

Two industry-wide popular load-flow software packages were used by the participating utilities to calculate transmission losses. GE Positive Sequence Load Flow Software (PSLF) was used by two utilities, and Siemens Power System Simulator for Engineering (PSS®E) was used by six utilities.

The methods used to calculate transmission losses for each participating utility are described below. Appendix A presents more details on the assumptions of each loss study, calculations, and approaches for each utility.

[5] *Distribution System Losses Evaluation*, EPRI, Palo Alto, CA: 2008. 1016097.

Utility A

Utility A calculates transmission losses at peak and uses loss and load factors by voltage level to calculate annual energy losses:

- Conductor/cable losses calculated in PSLF.
- Substation transformer losses included with reported transmission losses:
  - Used peak loading.
  - Used manufacturer test reports for load and no-load losses of transformers.

Utility B

Utility B calculates transmission losses at peak and uses a system-wide loss and load factor to calculate annual energy losses:

- Conductor/cable losses calculated in PSLF.
- Corona losses for overhead transmission considered but found to be negligible.
- Dielectric losses for insulated underground feeders found to be insignificant.
- Substation transformer losses included with reported transmission losses. Used metered loads for load losses and test reports for core losses.
- Transmission “unaccounted for” losses identified with metering in place.

Utility C

Utility C calculates transmission losses at peak and uses a system-wide loss and load factor to calculate annual energy losses:

- Conductor/cable losses calculated in PSSE.
- Corona losses for overhead 345-kV feeders were calculated using parameters such as radius, number of conductors in a bundle, bundle centers, configuration, phase spacing, voltage, line altitude, weather conditions, and some defined constants.
- Dielectric losses for insulated underground feeders were calculated using voltage, diameter, a dielectric constant for the insulating material, and a dissipation factor.
- Substation transformer losses, included with reported transmission losses:
  - Used metered loads for load losses and test reports for core losses.
  - Used 105 percent voltage rating to calculate no-load losses.
- Substation equipment losses, such as phase-angle regulators and shunt reactors, were calculated using data from manufacturer test reports.

Utility D

Utility D, which is a transmission-only utility, calculated losses at peak only:

- Conductor/cable losses calculated in PSS®E.

- GSU and substation transformer losses calculated in PSS®E.
- For the 115-kV system (referred to as “Zone D,” which serves customers directly), a separate model was developed and an hourly analysis was performed using revenue metering data.

Utilities E and F

Utilities E and F operate as subsidiaries under the same holding company. The same methodologies are used to calculate losses at both utilities. Utilities E and F calculate transmission losses at peak and use a system-wide loss and load factor to calculate annual energy losses:

- Conductor/cable losses calculated in PSS®E.
- Substation transformer losses included in transmission losses for Utility E. Used metered loads for load losses and test reports for core losses.
- Substation transformer losses included in transmission losses for Utility F. Used metered loads for load losses and test reports for core losses.

Utility G

Utility G calculates transmission losses at 12 different on/off peak load levels and uses a system-wide loss and load factor to calculate annual energy losses:

- Transmission and sub-transmission losses are calculated separately.
- Conductor/cable losses calculated in PSS®E.
- Substation transformer losses included in sub-transmission losses. Used metered loads for load losses and test reports for core losses.

Utility H

Utility H calculates transmission losses at eight different on/off peak load levels and uses a load-duration curve to calculate annual energy losses:

- Transmission and sub-transmission losses are calculated separately.
- Conductor/cable losses calculated in PSS®E.
- Substation transformer losses included in transmission losses. Used metered loads for load losses and test reports for core losses.

Industry Practices

There are various methods for calculating transmission losses, which include a range of data input types, assumptions, and methodologies. At a high level, transmission losses are simply energy inputs into the transmission system minus energy outputs at customer, substation, or primary metered locations. Transmission systems are complicated and are dynamic in nature. Electricity flows in many possible directions because transmission systems are designed in a networked configuration for reliability. Configuration, lines in and out of service, and generation dispatch are changing regularly. With all of that in mind, an hourly analysis of the transmission system utilizing generation dispatch and load-duration curve data is a detailed method for determining losses. Accuracy depends on metering quality and missing data.

Some key principles regarding transmission efficiency were identified in the EPRI Transmission System Efficiency Technology and Methodology Assessment Report.[6] These principles are as follows:

- **Efficiency is more than simply reducing losses:** An efficient system is low in losses, but it also has increased utilization of existing transmission assets and enables smarter integration of renewable resources and storage technologies.
- **Reliability remains a primary focus in efficiency initiatives:** There are technologies and practices available that increase the efficiency of the transmission system while maintaining or enhancing reliability.
- **Efficient transmission will be built on the shoulders of existing systems:** More transmission is essential for enabling the integration of renewable resources, improving reliability, and achieving increased efficiency. Sensors, communications, and using data to achieve greater control are key enablers for achieving and improving efficiency.
- **Efficiency must be included in future business cases:** Proposed transmission projects to improve capacity and voltage stability, as well as transmission improvements to connect to such clean and innovative energy technologies as renewable resources and storage, must include efficiency considerations as part of a comprehensive energy-delivery resource plan.
- **A regulatory framework with incentives is needed to unlock the potential:** To promote transmission efficiency, revisions to the regulatory framework might be required.

Input from participating utilities, EPRI, SAIC, and NYSERDA at the project workshop and throughout the project helped shape evaluate practices in calculating transmission losses.

Key Methodologies Used in the Industry for Loss Calculation

Various practices are used in the industry to calculate transmission losses. Primarily, the difference between various methods is the number of load data points to consider for the calculation. As described below, the methodologies range from utilizing one load level to 8760 hourly load patterns for building the power-flow model and calculating the system losses.

- **Peak Analysis –** Run a single coincident peak system load flow and develop loss factors to calculate annual energy losses. This method is used in the industry, but it is not recommended as a "leading practice" due to reduced precision in results compared to other available methods used. Static state estimation can be used in analyzing a snapshot of a single peak load. Peak analysis does not factor in how changing levels of dispatch and transmission system configuration impact flows and losses.
- **Multiple Load Levels –** Obtain seasonal load and resource data and run a number of scenarios with a power-flow model to get an AC solution with loss factors on the appropriate transmission lines and transformers. Integrating information from multiple measurement snapshots can improve results using state estimation. More scenarios lead to more granularity

[6] Transmission System Efficiency Technology and Methodology Assessment. EPRI, Palo, Alto, CA: 2010. 1017894.

in results but also increase the labor time required to run the analysis. There is a trade-off between the precision expected for the results and the labor burden to conduct the analysis. Usually in loss studies, at least six scenarios are necessary, representing six load levels: peak, minimum, and four intermediate levels for both a summer and winter season, with various levels of generation, as noted in the EPRI Transmission System Efficiency Technology and Methodology Assessment.

- **Analysis of Hourly Load Level Scenarios –** This method involves collecting hourly data points for the loss calculation. This approach generally provides more accurate results. Depending on the source of load data and analysis tools, the following approaches could be used under this method:
  - **Historic Load and Resource Data –** Obtain a full year or several years of load and resource hourly numbers to plug into a power-flow model to get an AC solution with loss factors on the appropriate transmission lines and transformers. The actual data would be best to determine the actual loss that the system had for the year rather than using a shaped seasonality or adjusted peak loss factor.
  - **SCED –** Use specialized software to do a security constrained economic dispatch (SCED) analysis. This analysis utilizes a co-optimized commitment and dispatch algorithm to run an hourly evaluation with a DC flow model. The analysis will have changes in demand and generation, resulting from factors such as time of day and seasonality, and will calculate the annual system losses on an hourly basis:
    - Hourly solutions account for transmission constraints as well as N-1 contingency conditions. Intermittent resources such as wind and solar can be modeled with project-specific 8760 hourly production patterns applicable to the region under study. Thermal resources can be modeled with capacity segments and associated incremental heat rates to allow for granular dispatch adjustments. Calculations from the DC flow model can be done using utility-provided load flow transmission system characteristics to determine hourly system losses.
    - Due to changes in generation and demand, resulting from factors such as time of day and seasonality, an hourly model is used to calculate system losses. No-load losses can be added to the load losses calculated with the SCED analysis.
    - It is important to note that SCED analysis evaluates only real power. Because it is a DC model, only real transmission losses are captured. Loss improvements with voltage/VAR optimization cannot be captured using this type of analysis.
  - **State Estimator –** Using hourly State Estimator data, there are multiple methods to determine the system loss factors. The most accurate method is to utilize a modeling platform for analyzing a transmission system. Some models that are widely used include PSLF, PSS®E, and PowerWorld Simulator (by PowerWorld Corporation). The packages for analyzing transmission systems are loaded with the captured meter data, and a state-estimator module in the computer model matches the conditions of the power system in the model to what was measured. Once in this condition, the loss factors can be directly calculated and output from the model:
    - Using a state estimator, the model is not an exact reproduction of the system. Collected field data and utility staff's knowledge of the system could help in error

checking. A solution is considered good when there is a high level of consistency between the estimated solution and actual measured data.

- From experience and research, there are three important basic elements needed for successful solutions using a state estimator:
  - A redundant, reliable, and accurate measurement set.
  - Accurate network topology, constructed from the real-time status of switching elements.
  - Accurate parameters for the network elements.

– **Actual Measured Data (Without State Estimator) –** Alternatively, if a state estimator is not used, total area load and generation can be modeled for each hour as measured without matching overall conditions, and the loss factors are then calculated. This method provides less precision and requires less sophistication.

Tools for Evaluating the Economic Benefits of Improvements to a Transmission System

From an EPRI report on transmission system efficiency technology and methodology assessment,[7] there are two main modeling approaches to evaluate the annual benefits of improvements to the efficiency of a transmission system:

- **Production Cost Simulation Models –** Used to calculate the minimum system generation cost while adhering to a wide variety of operating constraints and multiple outputs such as hourly generator dispatch, production costs, power flows over transmission components, fuel consumption, and market clearing prices. Analyzes normal and contingency conditions. Models develop into hourly chronological Security Constrained Unit Commitment (SCUC) and Security Constraint Economic Dispatch (SCED) simulation software. Packages include: PROSYM, GE MAPPS, PROMOD®, UPLAN, and DYNATRAN.
- **Power Flow/Optimal Power Flow (OPF) Models -** The OPF model can be applied to determine the generation economic dispatch subject to a number of specified operational constraints such as thermal limits on lines and transformers, voltage constraints, interface constraints (such as stability), and spinning reserve requirements. OPF automatically adjusts controls to attain the best possible solution that simultaneously satisfies system constraints given a pre-determined objective. OPF models, like conventional power flow, are used to analyze one single operating condition at a time. To assess annual benefits of measures to improve transmission efficiency/utilization, a series of separate snapshots of the system load levels and operating conditions thought to be most relevant for the problem at hand is first evaluated.

A full comparison of the two tools, from the EPRI final report, is presented in Table 2-2 below. [8]

[7] *Transmission System Efficiency Technology and Methodology Assessment.* EPRI, Palo Alto, CA: 1020143. 2010.

Table 2-2
Comparison of Production Cost Models vs. OPF/Power Flow

Production Cost Model	OPF/Power Flow Model
Advantages	**Advantages**
• Allows simulation of all the hours in a year, providing better estimate of production cost, congestion, emissions, etc. • Enables the simulation of the market on a forecast basis. • Allows us to look at all control areas simultaneously and evaluate the economic impacts of decisions. • Allows market analysis/ transmission analysis/planning. • Linked to power-flow models.	• Full representation of transmission network with controls. • Optimal security constrained generation dispatch (in OPF models). • Possibility to represent method to reduce losses, such as active and reactive optimization of power controls (OPF models). • Accurate representation of transmission losses. • Large numbers of security constraints.
Disadvantages	**Disadvantages**
• Simplified representation of transmission network, the effect if voltage and VARs are not accounted for. • Calculation of transmission losses is approximate (some models provide more accurate representation of losses, but the computation burden is increased). • Requires significant amounts of data. • Allows a limited number of selected security constraints. • Long processing times. • Requires significant benchmarking. • Time-consuming model-building process. • Does not model reliability to the same extent as power flow does.	• Only one hour at a time can be evaluated: yearly energy cost, losses, emissions, and other parameters are approximately estimated by selected number of snapshots. • Does not solve unit commitment. • Requires significant effort to prepare scenarios for analysis. • Not suitable for energy resource analysis.

Furthermore, from a simulation of a detailed 8760 hourly analysis using the two approximation methods, the following conclusions were found:

- The OPF/Power Flow models are able to accurately calculate the impact of efficiency measures in demand losses, power cost, and CO_2 emissions for one single operation condition.
- The determination of total annual values of the parameters being evaluated brings a great deal of approximation in the OPF/Power Flow models, because it is based on the analysis of a reduced number of scenarios.

[8] *Transmission System Efficiency Technology and Methodology Assessment.* EPRI, Palo Alto, CA: 1020143. 2010.

- Selecting 12 or more scenarios provides reasonably accurate results, solving a tradeoff between accuracy and calculation efforts. Some commercial production cost packages have very powerful modeling and calculation capabilities, but they are generally very expensive, they require significant amounts of data, and it is very time-consuming to build models.

Factors Affecting Transmission System Losses

The following is a description of major factors that can affect transmission losses for a system.

Metering Data

Accurate metering of loads, generation, and transmission interties is critical to reconcile load-flow analysis to determine transmission losses. Some utilities are using metering to reconcile the losses from the transmission interconnection to the low side of the distribution substations. There is a margin of error with this method because much of the utility metering is not revenue-grade metering. However, for the purpose, it provides useful information. Typically, utility interchanges have revenue-grade metering that provides accurate data. However, at distribution substations, the metering data is not revenue-grade.

Generation Dispatch

Generation dispatch and flow-through are becoming more of a concern to transmission planners as the penetration of intermittent resources increases on both transmission and distribution systems. During peak load conditions, these local resources can result in lower system losses because they are closer to the load than other generation.

However, these distributed generation resources can result in higher-than-normal transmission losses when this generation is operating at the times of lower local load conditions and must travel further on the transmission system, resulting in higher losses during these periods. The reduction on loading from the bulk transmission interties can be assessed to determine whether overall losses are increased.

Transmission Congestion

Another current issue that may be increasing transmission losses is transmission congestion. Transmission congestion can cause some highly loaded lines with higher than normal losses. Variable renewable generation and a lag in construction of transmission lines can increase congestion. Congestion results in transmission operators running their system more closely to limits, which results in higher losses.

Summary

As evident from the discussions in this section, there is no one standard practice in the industry when it comes to calculating losses in a transmission system. Depending on the characteristic and uniqueness of a system and operation in a region, a utility may prefer one method over others. However, all methods discussed above are acceptable industry wide. It is always a balancing act for a utility to adopt a method that gives accurate results but at the same time is practical to implement.

3
METHODOLOGY TO CALCULATE DISTRIBUTION LOSSES

This section summarizes the methodologies for calculating distribution losses described in the loss studies provided by participating utilities. Loss studies from the participating utilities were reviewed, and telephone interviews were conducted with each utility to discuss the methodologies and loss findings included in their loss studies in more detail.

The percent losses of total distribution system power requirements varied among utilities. The likely causes of variations are different categorization of losses, differences in the age of facilities, differences in voltage classes, feeder lengths, loading patterns, and differences in the methodologies used to calculate losses. There is not a uniformly defined approach across the industry because each utility's electrical system is unique and the availability of information and data varies from utility to utility. Different, reliable methodologies have been developed over the years to calculate losses based on the information that is available to each utility, which allows them to arrive at valid results.

Summary of Distribution Losses and Calculation Methodologies

Table 3-1 is a summary of the loss statistics reported by the participating utilities. Annual energy losses for the distribution systems ranged from 1.90 percent to 4.56 percent. The distribution losses as a percent of the total system losses ranged from 33.7 percent to 64.9 percent.

Table 3-1
Breakdown of Distribution Losses by Utility

Electric System Losses (Annual Energy Losses)						
Utility	**Primary Distribution**	**Secondary Distribution**	**Total Distribution**	**% of Total System Losses**	**Unaccounted**	**% of Total System Losses**
A	1.70%	2.20%	3.90%	57.1%	--	--
B	2.53%	0.41%	2.94%	64.9%	--	--
C	2.89%	1.17%	4.06%	61.1%	0.83%	12.5%
D(1)	--	--	--	--	--	--
E	4.27%	0.29%	4.56%	43.6%	--	--
F	0.60%	1.30%	1.90%	50.0%	--	--
G	1.10%	2.20%	3.30%	33.7%	--	--
H	1.39%	2.50%	3.89%	60.8%	0.88%	13.88%
Average	2.03%	1.54%	3.49%	53.0%	0.88%	
Std. Dev.	1.21%	0.92%	0.91%	11.2%	0.07%	

(1) Transmission-only utility.

Table 3-2 presents summary loss statistics reported by a sample of U.S. utilities reviewed in an EPRI study evaluating electric system losses.[9] On average, the distribution losses reported by the New York utilities are consistent with the system losses reported by other U.S. utilities. The industry loss statistics showed greater variation, as indicated by the higher standard deviation, and a slightly higher average than the New York utilities.

Table 3-2
Industry Loss Statistics

Electric System Losses (Annual Energy Losses)			
	Primary Distribution	**Secondary Distribution**	**Total Distribution**
Average	2.36%	1.33%	3.30%
Std. Dev.	1.57%	0.89%	1.71%

Note: Data represents results for fourteen U.S. utilities.

Voltage levels of distribution feeders for the participating utilities range from 4 kV to 34.5 kV. Annual energy losses were determined from the calculated peak losses and loss factors.

[9] *Distribution System Losses Evaluation.* EPRI, Palo Alto, CA: 2008. 1016097.

Substation losses were included in the calculated distribution losses for utility F only. For the other utilities, substation transformers and equipment were included in the “transmission losses” category.

Various load-flow software packages were used by the participating utilities to calculate distribution losses: WindMil™ software by Milsoft Integrated Solutions, Inc.; Cooper Power System CYMDIST engineering analysis software; Distributed Engineering Workstation (DEW), PVL; and Primary Circuit Analysis (PCA) software. All utilities included conductor losses in their primary distribution losses.

Five of the seven utilities included distribution transformer losses with primary distribution losses. For the other two utilities, distribution transformers and equipment were included with secondary system losses.

For the utilities without “unaccounted” losses, all energy sales were reconciled into one of the “transmission or distribution loss” categories. “Unaccounted” losses may include theft and metering inaccuracies.

The loss-calculation methodologies for each participating utility are described below. As mentioned above, there is not one unified approach across the industry for calculating losses, and variations exist between the utilities. Appendix A presents more details on the assumptions of each loss study, calculations, and approaches for each utility.

Utility A

Utility A calculates distribution losses at peak and uses loss and load factors by voltage level to calculate annual energy losses.

- Primary losses:
  - Sampled distribution system at peak and extrapolated to system; sample size not identified.
  - Analysis software: WindMil™.
  - Primary conductor losses calculated in an engineering model.
- Distribution transformer losses:
  - Calculated in spreadsheet with assumption on number of customers, loading, and test reports.
  - Core losses included from test reports.
- Service and secondary losses: Calculated in spreadsheet based on standard sizes, lengths, and estimated loading.
- Distribution substation transformers:
  - Calculated in their own category, not necessarily transmission or distribution.
  - Used peak loading and manufacturer test reports for load and no-load losses.
- Meters: Did not include in evaluation.
- Unaccounted: Energy sales were reconciled into one of the “distribution loss” categories.

Utility B

Utility B calculates distribution losses at peak and uses a system-wide loss and load factor to calculate annual energy losses.

- Primary losses:
  - Calculates losses for all distribution feeders (no sampling).
  - Analysis software: Distributed Engineering Workstation (DEW).
  - Primary conductor losses calculated in engineering model.
  - Dielectric losses for insulated underground feeders found to be insignificant.
- Distribution transformer losses:
  - Load losses calculated from engineering model.
  - Test reports used for core losses.
- Service and secondary losses: Calculated as difference between total measured losses by category and sum of calculated losses.
- Distribution substation transformers:
  - Included in transmission losses.
  - Used metered loads for load losses and test reports for core losses.
- Meters: Did not include in evaluation.
- Unaccounted: Estimated for transmission and distribution.

Utility C

Utility C calculates distribution losses at peak and uses a system-wide loss and load factor to calculate annual energy losses.

- Primary losses:
  - Sampled distribution system at peak and extrapolated to system by analyzing peak current through different sizes of conductors and using property records to determine conductor/cable lengths on the system; sample size not identified.
  - Analysis software: PVL (in-house software).
  - Primary conductor losses calculated in engineering model.
  - Dielectric losses for insulated underground feeders were calculated using voltage, diameter, a dielectric constant for the insulating material, and a dissipation factor.
- Distribution transformer losses: Calculated load and no-load losses from test report data.
- Service and secondary losses: Calculated from average normal loading of distribution transformers and assumed conductor/cable sizes per transformer kVA size.
- Distribution substation transformers:
  - Included in transmission losses.

  - Used metered loads for load losses and test reports for core losses.
  - Used 105 percent voltage rating to calculate no-load losses.
- Distribution equipment, such as network protectors, shunt reactor, regulators, and capacitors: Losses were calculated using manufacturer test report data.
- Meters: Calculated based on accuracy testing of meters and known energy requirements for meters.
- Unaccounted: Includes theft and other.

Utility D

This is a transmission-only utility.

Utilities E and F

Utilities E and F calculate distribution losses at peak and use a system-wide loss and load factor to calculate annual energy losses.

- Primary losses:
  - Sampled distribution system at peak and extrapolated to system; sample size not identified.
  - Analysis software: Primary Circuit Analysis (PCS, in-house software).
  - Primary conductor losses calculated in engineering model.
- Distribution transformer losses:
  - Calculated using the transformer load-management database using a load factor of 62.4 percent.
  - Includes load and no-load losses.
- Service and secondary losses:
  - Sampled secondary distribution system at peak and extrapolated to system.
  - Analysis software: Primary Circuit Analysis (PCS, in-house software).
  - Secondary conductor losses calculated in engineering model.
- Distribution substation transformers:
  - Included in transmission losses for Utility E.
  - Included in distribution losses for Utility F.
  - Used metered loads for load losses and test reports for core losses.
- Meters: Did not include in evaluation.
- Unaccounted: Energy sales were reconciled into one of the “distribution loss” categories.

Utility G

Utility G calculates distribution losses at peak and uses a system-wide loss and load factor to calculate annual energy losses.

- Primary line losses:
  - Sampled distribution system at peak on 16 circuits and extrapolated to system.
  - Analysis software: CYMDIST.
  - Primary conductor losses calculated in engineering model.
- Distribution transformer losses: Calculated load and no-load losses from test report data.
- Service and secondary losses: Calculated based on number and size of distribution transformers connected to feeders analyzed, as well as typical wire configurations chosen based on size of transformer.
- Distribution substation transformers:
  - Included in sub-transmission losses.
  - Used metered loads for load losses and test reports for core losses.
- Meters: Did not include in evaluation.
- Unaccounted: Energy sales were reconciled into one of the “distribution loss” categories.

Utility H

Utility H calculates distribution losses at peak and uses a load-duration curve to calculate annual energy losses.

- Primary losses:
  - Sampled 60 percent of distribution system, 530 feeders, at peak and extrapolated to whole system.
  - Analysis software: CYMDIST.
  - Primary conductor losses calculated in engineering model.
- Distribution transformer losses:
  - Calculated using the transformer load-management database.
  - Includes load and no-load losses.
- Service and secondary losses:
  - Secondary calculated based on standard size, 1/0 triplex, and typical residential distribution transformer loading.
  - Services calculated based on standard sizes, historical data on average length, and number of residential meters.
  - Extrapolated to rest of system.
- Distribution substation transformers:

  - Included in transmission losses.
  - Used metered loads for load losses and test reports for core losses.
- Meters: Energy requirements accounted for meters and metering inaccuracies.
- Unaccounted: Includes theft, metering inaccuracies, and other.

Industry Practices

This section provides guidelines and highlights leading practices across the industry for categorizing distribution losses, determining what electrical components are most commonly included in a distribution loss study, and calculating the losses for each electrical component. The methods explored are a culmination of professional experience, reviews of research by others, input from the study participants, and reviews of loss studies from a number of utilities, including the participating utilities for this study.

Losses are defined as the difference between the energy put into the system and the energy that is utilized by the end users. Electric system losses can be technical losses—fixed and variable losses due to energizing equipment, current flowing through electrical devices, and consumption by equipment—or non-technical losses—typically attributed to equipment abnormalities, administrative errors in the metering and billing systems, meter inaccuracies, meter tampering, or theft.

Data

The data needed to calculate losses for each system component will vary based on the tools and models used by the utility. The following list describes the data and information that may be needed to perform a loss study.

- **System Data:** Historical system peak data and purchased and sold energy.
- **Substation Transformer:** Characteristics including metered peak loads, quantity, size, no-load iron (Fe) core losses, load, copper (Cu) coil impedance, and voltage levels.
- **Substation Equipment:** Characteristics including quantity, size, no-load iron (Fe) core losses, load, copper (Cu) coil impedance, voltage levels for voltage regulators, CT and PT instrumentation, meters, capacitors, auxiliary equipment, and bus losses.
- **Distribution Primary:** Conductor sizes and impedance definitions, lengths, loadings, representative feeders for each voltage class, customer type, and feeder type (urban or rural).
- **Distribution Transformer:** Characteristics including estimated loading, quantity, size, no-load iron (Fe) core losses, load, copper (Cu) coil impedance, and voltage levels.
- **Distribution Secondary:** Standard conductor sizes and impedance definitions, as well as lengths and loading.
- **Distribution Equipment Data:** Size, types, locations, and loss data of other distribution equipment such as regulators, capacitors, and street lights.
- **Load Data:** Load profile, power delivered at different times throughout the period.

- **Customer Data:** Number and type of customers for each voltage level served and metered load at all service points on a GIS-based system.

The development of a loss model incorporates supply, customer, and load data to calculate fixed and variable load losses for peak and average loading on system. It breaks down losses to detailed components, then calibrates so that the total sum of the components (including an estimate of “unaccounted for” losses) equals the estimated total system losses. Total system losses equal the difference between power delivered to the system or substation and total metered energy delivered to the end users.

Unmetered Loads

Unmetered loads, such as street lighting and station service, consume energy in the form of end-use load and losses. End-use load is not included in losses, but rather as part of the system load. The energy consumed by these components would be a mixture of fixed and variable loads. In many cases, losses incurred by unmetered loads are categorized in an “unaccounted for” category that consist of losses not specifically calculated in a technical loss category.

When information is available or can be calculated, there is value in identifying these losses in a separate category for unmetered loads. By doing this, system improvements can be made to target possible high-loss components. Manufacturer specification data for substation auxiliaries, lighting across the system, transformer fans, battery chargers, and so on typically contain part of the data necessary for calculating auxiliary consumption.

Transformers

In general, substation and distribution transformers account for a large portion of the total losses for an electric system. Utilities typically gather monthly peak data at the substation transformer level but do not gather peak data at the distribution transformer level, except for some commercial and industrial loads that have energy and demand data available from metering. Separating losses for substation transformer and distribution transformers allows for more meaningful benchmarking of loss data.

For some utilities, metering equipment is not in place to have metered data for each substation transformer to aid in calculating losses. Because substation transformer losses are one of the larger components of system losses, there is much value in obtaining the metered data, at least on a monthly basis to be able to extract peak data to be used in loss calculations. Load and no-load losses are important components to be accounted for in calculating loss in substation transformers. As advanced metering infrastructure (AMI) becomes more widely used, utilities will be able to use that data to better quantify distribution transformer loading and losses.

Specific information on distribution transformers and secondary/service drop conductors is often not available. Estimation techniques are the preferred method in lieu of performing additional field collection for the calculation of losses. Collecting specific information on each transformer or secondary/service line is time-consuming and costly. To aid in estimating losses for these categories, a widely used approach for determining the peak and annual energy losses for distribution transformers is described below:

1. Calculated total distribution peak load compared to total available distribution transformer kVA, by voltage class, can provide the ratio of peak load to connected load. This can be performed for each feeder as in the example presented below:
   - Peak feeder load = 3,500kVA; Sum of distribution transformer name plate = 6,200kVAConnected load ration = 3500/6200 = 0.5645
   - Total annual energy delivered by feeder = 15,000MWh
     Load factor = 15000000/8760/3500= 0.489 [See Appendix B – Eq.1]
   - Loss factor = (0.85)*(0.489$^{2)}$ + (0.15)*(0.489) = 0.277 [See Appendix B – Eq.3]
2. A transformer database can provide the number of distribution transformers by voltage class, and there are numerous industry resources available with manufacturer test report data for each transformer size, by voltage level, that can be used to calculate peak losses. If available, utility-specific manufacturer test report data would provide more precision in this estimating technique, especially where newer and more efficient transformers have been installed over the years. Many available resources available include average impedance data for older transformer styles. Load and no-load losses are typically accounted for in distribution transformer loss calculations. See Table 3-2 for a continuation of the example.

Table 3-2
Example Transformer Data for a Feeder

Transformer Size	Quantity	Total Connected kVA	Connected kVA Ratio	Load Losses (kW)	No-Load Losses (kW)
15	40	600	0.565	0.179	0.076
25	76	1,900	0.565	0.295	0.109
50	28	1,400	0.565	0.505	0.166
75	20	1,500	0.565	0.663	0.274
100	8	800	0.565	0.881	0.319
TOTAL	172	6,200	--	--	--

3. Use the calculated load factors and system loss factors from Step 1 to calculate annual energy losses. See Table 3-3.

Table 3-3
Distribution Transformer Calculated Annual Energy Losses Example

Transformer Size (kVA)	Quantity	Total Connected kVA	Connected kVA Ratio	Load Losses (kW)	No-Load Losses (kW)	Loss Factor	Calculated Losses at Peak (kW)	Annual Energy Losses (kWh)
15	40	600	0.565	0.179	0.076	0.277	5	13,571
25	76	1,900	0.565	0.295	0.109	0.277	15	38,371
50	28	1,400	0.565	0.505	0.166	0.277	9	23,654
75	20	1,500	0.565	0.663	0.274	0.277	10	25,937
100	8	800	0.565	0.881	0.319	0.277	5	14,430
TOTAL	172	6,200	--	--	--	--	44	115,963

Note: See Appendix B, Eq. 4, 5, 6, and 8.

Peak Demand and Annual Energy Losses

Generally, a study of losses in a distribution system includes the losses of each component in that system, from the customer meter up to the substation transformer for both peak and energy losses. Peak demand losses are commonly calculated at the coincident peak for each level calculated. Energy losses are typically calculated one of two ways:

1. Use hourly data to calculate losses for each hour of the time period. This is the most data intensive approach.
2. Calculate energy losses based on the peak loss of the equipment or at the feeder level multiplied by the loss factor for the equipment or feeder. It is common to use annual data, and monthly data could offer increased precision. Monthly data would increase the cost and complexity of the analysis but may add additional insight into seasonal variation and may add accuracy for loads with atypical load shapes.

While not always available, hourly data will allow more detailed studies and calculations to be performed, resulting in increased granularity in the results. Using annual data will require more assumptions and the use of system average data, which can lead to less precise results. Hour-by-hour analysis requires detailed data collection and modeling. Such detailed modeling allows analysis of how losses vary with time and may allow modeling of volt-var control systems.

Because hourly data is not typically available to calculate losses for each hour, the most common practice is to calculate peak load losses and use a loss factor to develop an annual energy loss value. A commonly used formula to calculate annual energy losses is referred to as the *Hoebel coefficient method* (see Appendix B). This equation was used in all but two of the participating utilities studies, where one did not calculate annual energy losses and the other used a load duration curve method.

Sampling versus Whole System Approach

Because detailed information is not always available, utilities commonly use sampling techniques to determine losses for each loss category. The preferred sample size is relative to the size of the system. There are more than likely certain atypical feeders that can be evaluated individually, but for the rest of the feeders, a representative sample from each voltage class can be selected that are similar enough to others on the system to provide reasonable extrapolated results.

The most common approach for the participating utilities, based on the 2008 loss studies evaluated, was sampling. Given the size of each distribution system, ranging from 5,600 miles to 63,025 miles of primary circuits, modeling each feeder can be tedious and costly. Sampling is a relevant approach and is widely used across the industry.

Several of the participating utilities are moving towards modeling the entire primary distribution system in various engineering load-flow software. There is value in calculating the losses for each distribution feeder over sampling some representative feeders and extrapolating the results. A higher level of granularity and precision is obtained through this approach. Also, identification of losses in more specific areas of the distribution system allows for application of loss-mitigation strategies that can be unique to each area of the system. Collecting system information, not already obtained, for use in a full distribution system model can be cost-prohibitive. If the costs and benefits are considered, the outcome will most likely be different for each individual utility. Utilities can develop a screening process that would identify likely areas that might benefit from having a more detailed analysis performed.

Computer Simulation

Computer simulation can be used to economically calculate losses in primary distribution lines. The two basic methods of load allocation are by connected kVA or by connected kWh (energy delivered to the customer from metered data). Allocation by connected kVA requires knowing where the transformers are located on the system and the size of the transformer. Allocation by connected kWh requires a connection between the utility’s billing data and the location of the customer in the computer model. Both methods have advantages and disadvantages. The connected kVA method assumes the transformers are loaded to the same level, and the connected kWh method assumes an average demand and may not accurately represent peak conditions incurred by seasonal load customers.

Losses in Secondary and Service Lines

Secondary lines and service drops to serve electric utility customers are not typically modeled in engineering analysis load-flow software. A small percentage of U.S. utilities have detailed models down to the consumer level, including secondary and service lines. Although source-to-customer computer simulation could offer more precise calculations, a widely used approach includes using a spreadsheet analysis where some known system information is included and a variety of different approximations are made depending on the method. Table 3-4 provides an example of a common approach used to estimate secondary and service drop losses. In some cases, customer class load factors are not readily available. In the example, system load factor is used to calculate the annual energy losses.

Table 3-4
Example of Secondary/Service Drop Loss Calculations

Customer Class	Number of Customers	Total Transformer kVA	Annual Energy Usage (kWh)	Annual System Load Factor	Calculated Peak Demand (kW)	Average Length per Service (ft)	Type of Secondary/ Service Drop	Ohms Per Foot	Service Voltage (kV)	Average Peak Demand Per Customer (kW)	Average Annual Demand Loss Per Service (Watts)	Annual Demand Loss (kW)	Annual Energy Losses (kWh)
Residential	22,276	78,437	154,736,000	74.07%	23,848	100	#2 TPX	0.000266	0.240	1.07	61.33	1,366.10	643,497
Commercial	4,673	40,077	79,085,000	74.07%	12,188	100	#1/0 TPX	0.000167	0.480	2.61	57.28	267.66	126,080
Large Power	561	75,440	148,850,000	74.07%	22,940	100	#1/0 TPX	0.000167	0.480	40.89	14,078.60	7,898.09	3,720,386
Primary Service	32	45,177	89,124,000	74.07%	13,736	--	--	--	--	--	--	0	0
Security Lights	4,827	2,586	5,096,000	74.07%	785	200	#2 TPX	0.000266	0.120	0.16	11.33	54.70	25,768
TOTAL	32,369	241,716	476,891,000		73,497							9,586.55	4,515,730

Notes:

1)Text in blue is input from utility records and manufacturer specifications (in the case of conductor resistance values).

2)Calculated Peak Demand is calculated from annual system load factor (column 5), annual energy usage per customer class (column 4), and 8760 hours.

3)Average Peak Demand Per Customer is calculated from the calculated peak demand (column 6) and number of customers (column 2).

4)Average Annual Demand Loss Per Service is calculated from the average peak demand per customer (column 11), the demand factor (∑((Monthly Peak)/(Annual System Peak)^2)), service voltage (column10), ohms per foot (column 9), and average length per service (column7)

5)Annual Demand Loss is calculated from the average annual demand loss per service (column 12) and the number of customers (column 2)

6)Annual Energy Losses are calculated from annual demand loss (column 13) and use of the Hoebel coefficient method explained in Section 4 in "Evaluating Cost of Losses"

Distribution Loss Study Examples

Calculation methods and equations for determining distribution losses are presented in Appendix B. Many of these methods are currently used by the participating utilities. Equations and methodologies for the following factors are included:

- Load and loss factors
- Substation transformers
- Primary lines
- Line equipment
- Distribution transformers
- Secondary and services
- Meters and other equipment
- Unmetered loads
- Streetlights
- Theft

A sample distribution loss study is provided in Appendix C, which includes a tool created by EPRI and SAIC to help calculate losses for the various components of a distribution system and summarize the results.

Summary

As evident from the discussions in this section, there is no unified standard practice in the industry when it comes to the calculation of distribution system losses. The cost of more detail may not always provide more value. Depending on the characteristics and uniqueness of a system and available tools and data, a utility may prefer one method over others. However, all methods discussed above are acceptable industry wide. It is always a balancing act for a utility to adopt a method that gives accurate results, but at the same time is practical to implement.

4
STRATEGIES TO MITIGATE LOSSES

Utilities strive to design and operate safe and reliable electric systems that operate efficiently and economically while meeting the needs of customers. There are areas where changes in operations or investment in equipment can reduce electric system losses; however, before taking corrective action, it is important for the utility to perform cost/benefit analyses to determine whether the proposed action is economical. Many loss-reduction techniques are not cost effective on their own but may be economical when system upgrades or improvements are made.

As utilities make improvements to their systems to reduce losses, it can help to first identify the cause of losses and separate losses into technical and non-technical categories. Technical losses are due to the loading and electrical characteristics of the electrical system; non-technical losses are caused by factors outside the electric system, such as metering inaccuracies, billing errors, and energy theft. Distinguishing the cause and type of losses can help in developing appropriate strategies to mitigate them.

The two main areas that utilities focus on to reduce losses are (1) replacing existing infrastructure and (2) changing design and planning criteria for future infrastructure investments to improve efficiency. The cost to replace existing infrastructure can be high compared to the cost savings through loss reduction; however, the incremental cost to build higher efficiencies into future capital projects could be low compared to efficiency gains.

This section summarizes the findings of the loss-reduction strategies evaluated by the participating utilities. It also discusses industry trends on loss-reduction strategies.

Loss-Mitigation Strategies Evaluated and Implemented by Participating Utilities

Each participating utility evaluated loss-mitigation strategies in the December 2008 reports filed in response to the PSC's Energy Efficiency Portfolio Standard. While there were many similarities in strategies, each utility identified some unique approaches best suited for its system. The utilities performed a cost/benefit analysis of each approach to identify the most economical choices. It should be noted that there are programs that utilities are implementing for reasons other than loss mitigation that also reduce losses, such as Paper Insulated Lead Cable (PILC) replacement. If these programs were not evaluated as part of the loss-mitigation strategies submitted to the PSC, then they are not included in Table 4-1.

The loss-mitigation strategies evaluated by the participating utilities are shown in Table 4-1, which includes how many of the New York utilities investigated each strategy.

Table 4-1
Loss-Mitigation Strategies Evaluated by Participating Utilities

Strategies	Count
Distribution voltage conversion	6
Install switched distribution capacitor banks	6
Distribution phase balancing	6
Replace distribution transformers with more efficient transformers	5
Reconductor transmission line	5
Transmission voltage conversion	4
Multi-phasing	4
Reconductor distribution line	4
Distribution circuit optimization	3
Advanced metering infrastructure (AMI)	3
Substation transformer purchasing criteria review	3
Super conductor	3
PILC replacement	3
Distribution transformer sizing	3
Install transmission capacitor banks	2
Substation equipment upgrades	2
New distribution circuit	2
Review planning criteria for capacitor placement	2
Asset management	2
Static VAR compensation	2
Use of trapezoidal conductor	2
Removal of unused distribution transformers	2
Replace underutilized distribution transformers	2
Review guidelines for new secondary installation and replacement for sizing	2
Distribution primary and secondary engineering models	2
Distribution line configuration and spacing	2
Distribution system control points	2

Strategies	Count
Theft detection	2
Infrared surveying	2
Transmission retention	2
Distributed generation (DG) VAR support	2
Low corona hardware and testing	2
Phase-shifting transformers	2
Seasonally bypassing reactors	2
Flexible AC transmission system	2
HVDC	2
Smart Grid	2
Phase ID program	2
Transmission operation methods review	1
Evaluate voltage controls	1
Evaluate energy efficiency at generating facilities	1
Install substation capacitor banks	1
Transformer load management	1
New substation transformer	1
Increase size of approved transmission line project	1
New transmission backbone	1
Undergrounding new transmission circuits	1
Transmission loops (specific areas)	1
Economic conductor evaluation	1
Convert overhead to underground	1

The participating utilities performed cost/benefit analyses for the majority of the strategies identified in Table 4-1 to determine which loss-reduction strategies should be investigated further or implemented. Loss improvements for the loss-reduction strategies being pursued were estimated as part of the economic analysis. However, actual results from implementation of the improvements were not specifically identified by the participating utilities to determine their effectiveness. From an economic standpoint, many of the strategies identified in Table 4-1 were determined by the utilities to not be cost-effective on a standalone basis for the purpose of reducing losses, although they may make sense to do in conjunction with other capital-improvement projects.

The more common loss-mitigation strategies currently being piloted (or already implemented) by the participating utilities include the following programs:

- Distribution capacitor installation
- Conservation voltage reduction (CVR)
- Phase balancing
- Upgrading the voltage class
- Installing more efficient transformers

Regarding transmission losses, a study performed for the NYISO examined ways to reduce losses on the state's bulk transmission system (230 kV and above).[10] In addition to hardware installation options, such as capacitors, to reduce transmission losses, the NYISO is exploring the use of Optimal Power Flow (OPF) software technology to dispatch the bulk electric system in New York more efficiently during non-peak hours. According to the NYISO report, 60 to 65 percent of the total annual energy loss on the bulk transmission system occurs during non-peak hours, which is also when system operators have more flexibility to make adjustments during lower load levels. OPF technology includes the capability to send real-time reactive power-management signals to generators and transmission facilities that could potentially reduce transmission losses. Initial results indicate that the use of OPF techniques during non-peak hours could be a cost-effective method for reducing losses. NYISO is conducting further studies. Some topics of interest that are being investigated relate to controlling the VAR output of generation, controlling load tap changers (LTCs) on the transformers in the bulk power system and evaluating switching capacitor banks on the high-voltage system.

Based on our review of the reports filed by the participating utilities and knowledge of other utilities, the following measures may be cost-effective in some situations to reduce losses.

For transmission systems:

1. Optimizing existing controls for transformer taps, generator voltages, and switched shunt capacitor banks reduces current flow and minimizes losses.
2. Adding shunt capacitor banks, fixed and switched, at points on the system closest to the reactive load source reduces current flow and minimizes losses.

For distribution systems:

1. Phase balancing reduces line and neutral conductor losses.
2. Distribution capacitor banks on the feeders to improve the feeder power factor reduces line losses.
3. Capacitor banks at or near the substation improve the station power factor caused from the substation power transformer var requirement, measured at the high side of the power transformer, and reduces load losses in the substation transformer.
4. Using life-cycle evaluation for equipment sizing (initial installation of distribution transformers and conductors) reduces transformer core and coil losses.

[10] "NYISO Transmission System Losses Exploration Study," ABB Grid Systems Consulting (2009).

Utilities can identify areas of the electric system that might have a higher potential for loss reduction and perform specific analysis for these systems to determine whether system improvements can be cost-effective in reducing losses. Approaches to calculating the cost of losses and performing an economic evaluation of efficiency improvements are reviewed in this report.

A recent EPRI study [11] found that most candidate projects involving reconductoring and advanced technologies cannot be justified solely on efficiency savings. The report further concluded that efficiency is typically a secondary or tertiary benefit to capacity and reliability enhancement for these candidate projects.

Other methodologies that can reduce energy use, but are typically not cost-justified by loss reduction alone, include:

1. Reducing end-use loads through demand management and energy efficiency programs for utility customers (such as window replacement, direct load control, insulating homes, and more efficient appliances). These methods reduce load and have only a minor impact on loss reduction.
2. Implementing voltage optimization (VO) or conservation voltage reduction (CVR). CVR has shown in recent studies that reducing voltage can reduce demand and energy consumption without impact to customers. VO, which is a technique that first "tunes" the distribution system by implementing system improvements and then applies voltage reduction, increases the amount that the voltage can be reduced for most feeders, thereby increasing energy reduction, and can reduce losses by two to four times as compared to just lowering the voltage. The additional loss reduction comes from the no-load losses in the distribution transformers and from implementing system improvements to tune the distribution system, in addition to the minor reduction in line loss from reducing the energy consumption of end-use loads. Voltage optimization is not strictly T&D efficiency, but many of the same approaches to analyzing losses and T&D efficiency apply to voltage optimization. It has the potential for much larger energy savings than loss reduction. See Appendix E for additional information.
3. Reconductoring of primary or secondary conductors.
4. Multi-phasing of single-phase primary lines.
5. Installing new feeders or substations.

From the review of reactive power tariffs, the participating New York utilities are incorporating reactive demand provisions similar to other utilities across the country. Documentation and feedback on the impact of reactive power charges to utility customers are sparse and inconsistent in the industry. Some challenges identified in the industry and for the New York utilities include:

- Some rates in place are not applied consistently or are made so transparent that it is difficult to be able to determine whether the rate structure design is actually motivating customers to perform corrective actions.
- Choosing a requirement for an optimal reactive demand level can be challenging. There are other unique challenges in dealing with real-time control of reactive power resources such

[11] *Transmission System Efficiency Technology and Methodology Assessment.* EPRI, Palo, Alto, CA: 2010. 1017894.

that having a single requirement would not produce optimal solutions at every point in the system.

- The penalties may not be steep enough to motivate the applicable customers to take action.

Industry research, such as EPRI's Distribution Green Circuits and Transmission Efficiency programs and the Northwest Energy Efficiency Alliance's Distribution Efficiency Initiative, as well as the studies performed by the New York utilities, demonstrate that the efficiency of the power-delivery system can be improved. These studies conclude that for targeted areas, loss reduction can sometimes be economically justified by implementing changes in operations and capital investment that can reduce losses in the electric grid. These studies also show that loss reduction cannot be cost justified for all cases using the marginal cost of producing the next watt of electricity as the major contributor to the benefit.

Industry Trends

The following discussion highlights some industry trends and widely used loss-reduction approaches that may be of value to utilities.

Transmission and Distribution Modeling

If models are already developed, use of system modeling software to analyze power flows in the electric system is the simplest and most accurate way to analyze proposed loss-improvement projects. The results from the power-flow analysis can establish the baseline for the electric system for the existing configuration. Modeling of system improvements can then be performed to determine the reduction in system losses that can be achieved. Economic analysis can be applied to determine the cost effectiveness of each loss-reduction technique.

In addition to analyzing power flows and loss-reduction scenarios, transmission and distribution models are also used for locating faults on the system, planning system upgrades, keeping an inventory of system facilities, analyzing scenarios for high-growth areas, placing capacitors, identifying low-voltage areas, assessing stability, and as an overall tool for operations staff to use on a daily basis.

There is a large number of different software platforms to choose from, each with similar functionality. It is important for utilities to do some research and comparisons before investing in their preferred software. There are other factors involved when choosing load-flow software, including compatibility with the utility's geographic information system (GIS), customer information system (CIS), outage-management system (OMS), and other integral utility data systems.

Figure 4-1 is an example of a load-flow diagram from a distribution model that highlights capacity percentage of the primary lines for a peak load analysis. The graphical representation of the feeders from the computer model allows users to quickly display problems.

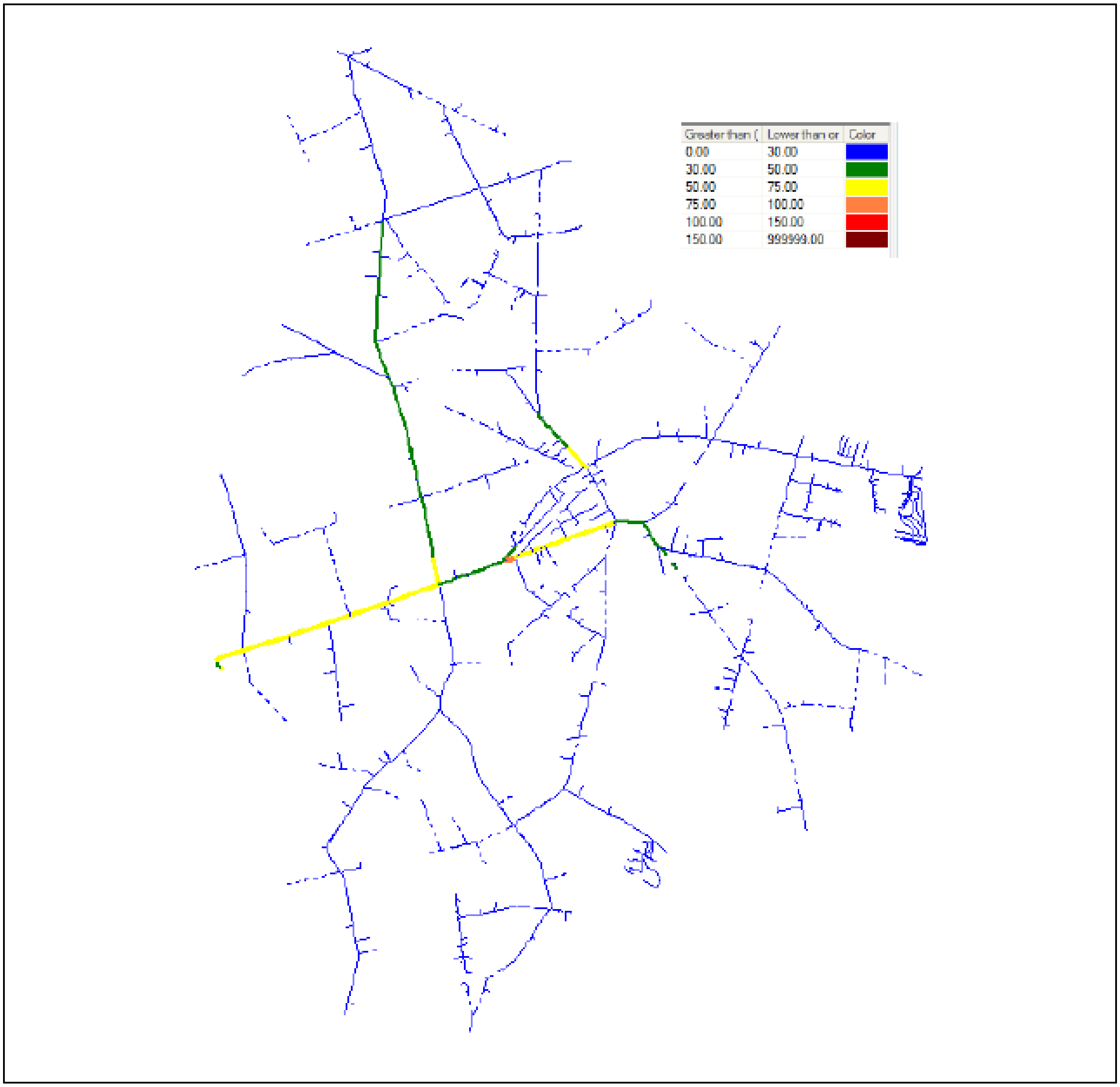


Figure 4-4-1: Sample Distribution Model

Load Balancing

Phase load balancing in a distribution system is one of the most cost-effective improvements that can be made to reduce losses in a distribution system. Reducing phase imbalance from 25 percent to below 10 percent can reduce primary line losses by 10 percent to15 percent, according to industry research [12].

[12] Northwest Energy Efficiency Alliance (NEEA), "Distribution Efficiency Study," 2007. http://tdworld.com/overhead_distribution/distribution-system-efficiency-20100201/

Figure 4-2 shows the results of a power-flow analysis on several distribution feeders. Loads were allocated as balanced and then re-allocated as unbalanced in 5-percent increments, and then line losses were determined. As shown, the percentage of line losses increases as the percentage of phase imbalance increases.

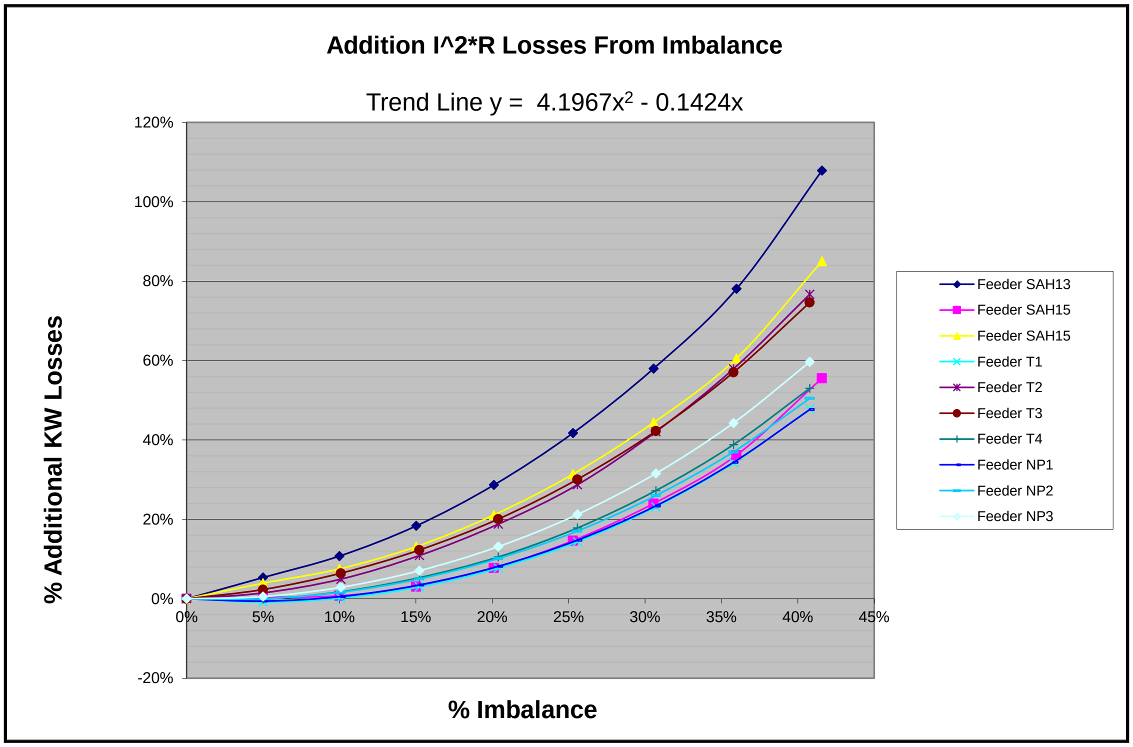


Figure 4-2: Increase in Line Losses due to Increase in Phase Imbalance

Balancing load between phases reduces average losses in the phase conductors by lowering current in one or more conductors. Due to the exponential loss of $I^2 \times R$, the sum of losses in the three balanced phases will always be less than any combination of loading scenarios. A balanced system will also reduce neutral return current to zero, eliminating the neutral losses in the return path.

Analysis of phase load balancing typically evaluates the load at the feeder source and at multiple points along the feeder and can be evaluated at different loading conditions. Phase balancing is commonly performed starting at the metering point furthest from the end of the circuit, such that each metering point achieves phase balancing around 5 percent to 10 percent. Even though the line current is highest during peak loads, peak loading occurs only for about one percent of the year. Phase balancing can be considered at other load levels as well, if data is available.

Evaluation of loss reductions for phase balancing is typically done using a system model and power-flow analysis. Most distribution load-flow analysis applications contain an option to assist the utility engineer in determining which load can be switched to balance load, and it will provide a summary of taps or transformers that need to be moved to balance the system at the modeled load levels. Phase balancing can be straightforward for overhead distribution systems. However, underground systems may prove challenging, depending on the system configuration. The recommendations from the computer simulations are typically verified in the field before they are implemented.

In addition to phase balancing, load balancing between feeders can reduce losses in distribution systems. Appropriate feeder balancing is achieved when the losses on each feeder included in the power analysis are equal. Feeder balancing can be performed by transferring load between feeders. Transferring load between feeders may be as simple as operating or installing manual or motor-operated switches. Often, more extensive construction may be required, such as multi-phasing a single-phase tap or building new three-phase sections of a line, adding significant cost and complexity.

The life expectancy of proper phase or feeder balancing is highly dependent on the load growth and configuration of the circuit.

Load balance can also be considered in configuring open-loop transmission systems. Power-flow analysis can determine the optimal open point to minimize losses. While most of the load balancing would be expected to occur on the distribution system, there is still potential opportunity for improvement on the sub-transmission and bulk transmission system to have more balanced loading between phases.

Power-Factor Correction

Capacitor placement, both at the transmission and distribution level, is a beneficial loss-reduction technique for many utilities. Some end-use loads and the distribution system equipment are inductive by nature, causing a lagging power factor and requiring the electric grid to supply reactive power to the distribution circuits. The addition of the reactive power (VAR) increases the total line current, which contributes to additional losses in the system. Figure 4-3 shows the increase in current and losses that occurs as power factor decreases.[13]

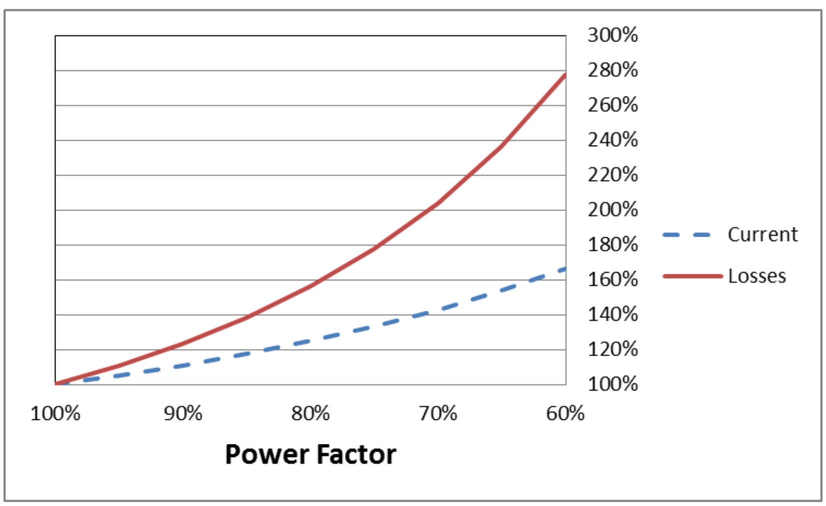


Figure 4-3: Current and Losses Versus Power Factor

Capacitor placement at or near the VAR load to eliminate or reduce the lagging power factor will reduce system losses and increase capacity in the primary lines and substation transformers by reducing the line current. The reduction in kW losses is proportional to the square of the reduction in line current.

[13] See Appendix H for a description of reactive power and its effect on losses.

The combined effect of inductive loads from the customers on the distribution circuit increases primary line losses. Power-factor correction at peak load conditions can reduce primary line losses and losses in the substation transformer. In some cases, the responsibility of power-factor correction is placed on the customer. For these customers, the power-factor correction (for example, installing capacitors) is commonly performed on the customer's side of the meter. Corrections made on the customers' side of the meter have an additional benefit to the utility in reducing system losses in the distribution transformer.

A power factor analysis is performed to determine the amount of reactive support needed in a system, whether it should be switched to prevent a leading power factor during periods of low load and the proper placement of the reactive support. Power-factor analysis is generally performed at the feeder level, but the effect on the substation transformer is also normally considered. Most distribution power-flow analysis software contains a module that can assist the planning engineer to optimize the placement and size of capacitors. The planning engineer needs to evaluate capacitor sizing and switching at various loading levels and conditions.

The key to placement and sizing of capacitor banks is to understand where the reactive power (VAR) load center is located on the feeder and the maximum and minimum VAR requirements. Fixed capacitor banks are commonly sized to the average annual minimum VAR requirements. If the difference between the maximum and minimum VAR requirements is large enough, then additional switched capacitor banks are typically used.

Primary Conductor Sizing

Increasing the primary conductor size on transmission and distribution circuits will reduce primary line losses by reducing the resistance in the line. Increasing the size of a primary conductor may also have effects beyond loss evaluation, because it may reduce voltage drop without having to make other more expensive improvements. This measure can also increase maximum operating capacity, allowing for more switching options under contingent conditions and leading to a possible increase in system reliability.

For new construction, the cost of selecting a larger conductor can be economically evaluated. Although the benefit of loss reduction alone may not be sufficient to justify reconductoring existing transmission and distribution circuits to a larger conductor size, combination with other benefits may make this improvement option more desirable. An economic analysis, in which the annual savings in the losses are balanced against the fixed charges of the cost of construction, will help determine the economical conductor size for new construction and for replacing conductors on an existing distribution circuit.

Industry research [14, 15] shows that the initial peak loading of a conductor is optimal around 30 percent of the conductor rating, and reconductoring can be cost-justified when the existing conductors are loaded as low as 50 percent to 60 percent during peak loads, depending on load factor and the expected growth rate for the feeder load.

[14] Mandal, S.; Pahwa, A.; , "Optimal Selection of Conductors for Distribution Feeders," *Power Engineering Society Winter Meeting, 2002. IEEE* , vol.2, no., pp. 1323 vol.2, 2002 doi: 10.1109/PESW.2002.985229.
[15] H. Lee Willis, *Power Distribution Planning Reference Book,* Second Addition, page 412. February 1, 2004.

Additional Feeders

Adding an additional feeder can reduce loading losses in two ways. First, the current in the existing feeder could effectively be cut in half, resulting in a reduction in $I^2 \times R$ losses, net of the losses in the new feeder. Second, there could be a net loss reduction in the substation transformers if the new feeder is fed from another substation transformer and the transformer losses serving the new feeder do not increase more than the loss reduction in the original transformer.

It is important to calculate total system losses for the existing configuration and for the new feeder configuration. In general, adding feeders cannot be cost-justified by loss reductions alone. Many factors need to be considered when adding transmission and distribution feeders, including cost analysis, reliability issues, growth estimates, and load diversity.

Distribution Transformers

The economic loading of distribution transformers is typically between 80 percent and 100 percent of nameplate rating for the initial peak loading (sometimes called first-year peak loading) [16]. Lower peak loading (80 percent for example) would be more applicable to areas with high growth rates, whereas areas that have relatively low growth rates may target higher loading for the initial peak.

Transformers that are lightly loaded operate inefficiently because of the no-load losses. Transformers that no longer have a load on them can be removed or de-energized from the system to reduce unnecessary no-load losses. On the other hand, when transformers are operated above the nameplate rating for the majority of the time, operating efficiency is reduced due to load losses.

The initial sizing of distribution transformers is challenging because the electrical infrastructure is typically installed before the customer facilities are constructed. Therefore, the utility has to develop an understanding of customer end-use loads and timing of load growth to properly size transformers for new construction.

To justify a transformer change-out for loss mitigation requires a clear understanding of the transformer loading, the benefits in reducing losses, and the cost to replace the transformer. The type of equipment is also typically considered, such as overhead versus pad-mounted transformers. Peak, average, and minimum loading on the transformers each play a role in determining whether a transformer change-out is practical.

Pole-top distribution transformers can operate at 150 percent of nameplate rating, and pad-mounted transformers can operate at 115 percent of nameplate rating without adverse impacts due to overloading, provided that the average loading is below nameplate. A transformer may be at capacity during peak load but spends the majority of the time lightly loaded. In this case, the no-load losses of an additional transformer will probably result in an increase in total losses. At the same time, economic evaluation of the secondary conductors is appropriate to determine whether secondary length can be reduced or increased in size to further reduce system losses.

[16] Spangler, Allen R., "The Economical Loading of Distribution Transformers," *IEEE Transactions on Industry Applications*, , vol.IA-13, no.2, pp.120–124, March 1977 doi: 10.1109/TIA.1977.4503374.

Existing transformer-sizing standards and guidelines may also be reviewed due to increases in transformer efficiencies. Changing load shapes and loss factors will influence the optimal balance of investment in iron and copper in transformers. Because of the higher emphasis placed on the cost of losses, purchasing higher-efficiency transformers may be economical when including the cost of losses and the capital costs. To evaluate the effect of all of these factors, utilities perform cost/benefit analyses. Given the cost for load and no-load losses, manufacturers can optimize the transformer design to provide the lowest life-cycle cost.

Secondary and Service Sizing

Secondary losses can be reduced by either upsizing conductors or reconfiguring the localized secondary to reduce secondary loading and length. Upgrading or reconfiguring a localized secondary may include distribution transformer sizing, primary line extensions, installation of additional secondary runs, and upgrades of secondary conductor sizes. For overhead secondary systems, changing the secondary system is straightforward, but for underground systems, this may be impractical due to directly buried cable or because the conduit size limits the size of secondary wire. In addition to the reduction of secondary losses, another benefit to reworking the secondary system is that it can improve power quality by reducing the impact of voltage flicker.

Substation Transformer

Balancing load on substation transformers is another way to reduce system losses. As a transformer load is increased, the $I^2 \times R$ losses in the transformer copper windings (load losses) increase exponentially. Load losses at capacity are approximately four times greater than running a transformer at half capacity.

When adding substation transformer capacity, the utilities consider such factors as cost, reliability, growth estimates, and load diversity. An additional substation transformer can reduce overall load losses by sharing the load of other transformers; however, the new transformer would add no-load losses to the system.

Some utilities perform a transformer economic evaluation when considering purchases of new transformers. The economic evaluations take into account the initial capital costs as well as the operating cost for the equipment. Likewise here, given the cost for load and no-load losses, manufacturers can optimize the transformer design to provide the lowest life-cycle cost. Several transformers from different manufacturers are typically compared to determine the optimal transformer choice by evaluating life-cycle costs.

Street Lighting

There are ways for utilities to reduce losses by updating streetlight technology in existing systems and/or by changing the utility’s lighting standards to require the use of more efficient lighting technologies in the installation of new streetlights. For example, replacing mercury vapor lamps in existing streetlights with high-pressure sodium vapor (HPS) lamps will result in significant reduction in energy consumption for street-lighting load. HPS streetlights rated at 100 watts (W) are available that produce the same lumen output of 175-W mercury lamps. Similarly, new energy-efficient lighting, such as light-emitting diode (LED), can reduce load and thereby reduce losses.

Upgrading the voltage level or adopting a higher voltage level for new street lighting installations can also reduce losses in the street lighting infrastructure. There are many voltage options available in today's street lighting selections. Selecting a 240-V lamp over a 120-V lamp will cut secondary line losses by a factor of four.

In addition, utilities can consider implementing a group re-lamping schedule and re-lamp at 70 percent of rated lamp life. Lights that operate longer than 70 percent of their rated life actually cost more in terms of the ratio of energy use to light output.

Metering

New electronic metering requires about 25 percent of the power required by older electronic equipment and 15 percent of the power required by electromechanical equipment. With this potential for loss reduction, changing metering equipment may make sense to a utility, especially if it can be rolled into another program such as an advanced metering infrastructure (AMI) program or a demand-management program. However, performing a cost/benefit analysis can help determine the cost effectiveness of changing metering equipment.

Substation Auxiliary Equipment

Many approaches exist to reduce energy consumption in substation installations, including making efficiency improvements in control rooms and buildings, and using higher-efficiency electrical auxiliary equipment, such as transformer fans, pumps, light and power transformers, heaters, and so on. Examples of non-electrical efficiency measures include improving insulation and weatherization of substation control buildings and installing higher-efficiency HVAC systems to keep equipment at normal temperatures.

The EPRI Transmission System Efficiency Technology and Methodology Assessment report [17] provides examples of measures being implemented in the utility industry to improve the unmeasured I^2R losses in substation auxiliary equipment.

Demand Management

Demand management is a broad term that encompasses many ways to reduce peak loading and energy requirements. Demand management involves working with end-use customers, typically larger customers, to curtail electrical usage on demand and to provide a network of smart devices, meters, and monitoring to reduce electric load for air conditioners, water heaters, or other large-demand equipment that are on at any given time. In addition, utilities have participated in energy efficiency programs focused on compact fluorescent lighting, higher-efficiency motors and appliances, efficient heating and cooling systems, or increased home insulation.

Demand management affects electric system infrastructure by reducing system peak load and energy requirements. Decreased current flow would result in reduced $I^2 \times R$ losses due to a reduction in end-use load. Determining the loss reduction caused by demand-management efforts, however, can be challenging because many of the demand-management programs are not deployed by the utility, but rather through the marketplace (for example, the locations where compact fluorescent light bulbs are used is not tracked, but there is an impact on overall load).

[17] *Transmission System Efficiency Technology and Methodology Assessment.* EPRI, Palo Alto, CA: 2010. 1020143.

The benefits of demand management reach beyond loss reduction. By reducing peak loading, some capital improvement projects could be eliminated or delayed, and the demand costs for peak generation or power acquisition will be lowered.

Appendix D is a case study for a project SAIC performed to evaluate the cost effectiveness of a distributed energy-storage system designed to help utilities reduce peak energy consumption for air-conditioned buildings.[18] The system uses thermally efficient, off-peak power to produce and store energy for use by air conditioners the next day, using a fraction of the peak energy required by conventional systems. It creates and stores cooling energy at night by freezing water in an insulated storage tank. The utility can dispatch it to cool during the day by circulating chilled refrigerant from that tank to the conventional air-conditioning system, eliminating the need to run the energy-intensive compressor during peak daytime hours.

The results showed loss reductions, improvements in voltage, capacity release, and improvements in power factor. Improvements in peak loss ranged from 8 percent to 20 percent per feeder, with analysis of a set number of cooling units placed. From a sensitivity analysis evaluating saturation levels, improvements in peak load loss ranged between 5 percent and 43 percent. The total reduction in peak load ranged between 2 percent and 23 percent. Figure 4-4 shows how the load is shifted from peak to off peak, reducing system losses.

The full case study is provided in Appendix D.

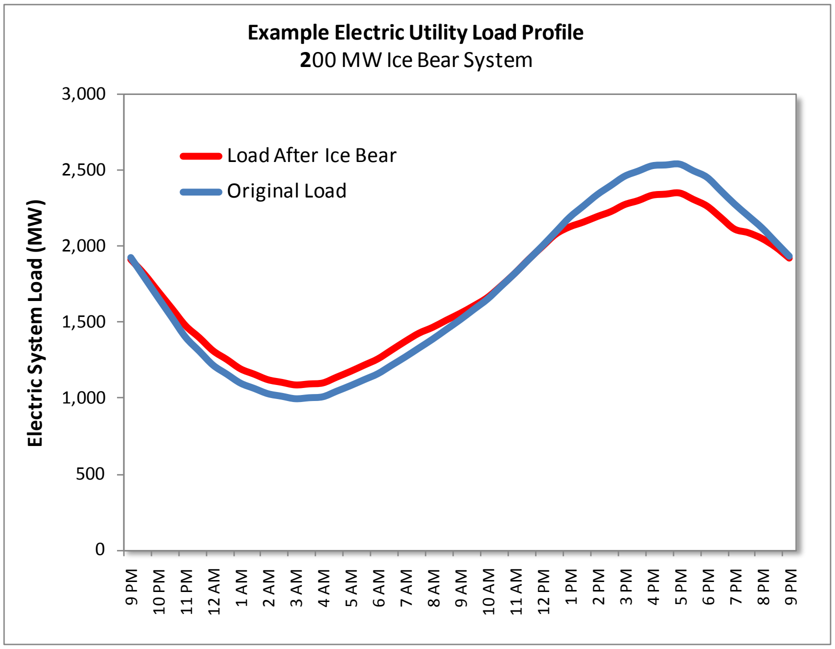


Figure 4-4: Load Shift due to ICE Bear Cooling System

Voltage Optimization

Electric load can be characterized from three load types: constant current (I), constant power (PQ), and constant impedance (Z). System losses for constant current load are not impacted by voltage, system losses for constant power loads will increase as the voltage decreases, and

[18] SAIC, "Technical Guide to Modeling an Ice Bear System," November 2010.

system losses for constant impedance loads will decrease as the voltage decreases. Many electric loads can be characterized by a combination of three load types, referred to as *ZIP* or *IPQZ* load models.

The relationship between the changes in electric power to the change in voltage is known as the conservation voltage reduction (CVR) factor and is expressed as $\%\Delta E/\%\Delta V$ p.u., where E can represent demand, energy, or VARs, and V is voltage. The net effect of voltage reduction on electric losses depends on the system CVR factors and power factor. For distribution feeders with power factor around 95 percent and a CVR var factor of 2.0, line losses will increase for CVR factors for real energy below 0.8 and decrease for a CVR factor above 0.8, whereas the distribution transformer no-load losses will decrease with any reduction in voltage. This is based on the basic power formula, $S = VI$, where S is the kVA, V is the voltage, and I is the current. Using this formula, the current would increase if the CVR factor for energy or demand is less than one. However, due to efficiencies in equipment operations, such as no-load losses and a higher CVR factor for reactive loads, the current does not appear to increase until the demand or energy CVR factor is below 0.8 p.u. For lower system power factors, for example 85 percent, current and losses will typically decrease for CVR demand factors as low as 0.6. As the CVR factor for reactive loads increases, with a lower system power factor, current and losses may begin decreasing for CVR demand factors less than 0.6. Table 4-2 illustrates the above stated concept.

Table 4-2
CVR Factors

Case	CVRf (kW)	CVRf (kVAR)	Power Factor (%)	Decrease in Voltage (%)	Change in Current (%)
1	0.6	2.0	95%	1.0%	0.27%
2	0.8	2.0	95%	1.0%	0.08%
3	1.0	2.0	95%	1.0%	-0.10%
4	0.6	2.0	85%	1.0%	0.01%
5	0.8	2.0	85%	1.0%	-0.13%
6	1.0	2.0	85%	1.0%	-0.28%
7	0.6	5.0	85%	1.0%	-0.81%
8	0.8	5.0	85%	1.0%	-0.96%
9	1.0	5.0	85%	1.0%	-1.11%

Case 2 illustrates that the current is basically unchanged given a CVR factor of 0.8. Case 1 has a lower CVR factor and the current increases, and Case 3 has a higher CVR factor and the current decreases. A higher reactive power CVR factor or a lower native power factor will tend to move the energy or demand CVR factor lower before the current starts to increase. Accounting for no-load losses in the distribution transformer will also lower the CVR factor before the current starts to increase.

The process of modeling loss reduction due to voltage optimization is complex. It requires the knowledge of end-use load types (electric space or hot water heating, gas space or hot water heating, heat pump, or air conditioning), their ZIP coefficients, and the voltage reduction. End-use load is the best predictor of CVR factors, as determined from the NEEA Distribution Efficiency Initiative study completed in 2007.[19] The electric heating loads, shown as the blue

[19] Northwest Energy Efficiency Alliance and SAIC, Inc., "Distribution Efficiency Initiative," December 2007. http://www.saic.com/news/resources.asp?cat=Energy, Environment, and Infrastructure&type=White Paper#

bars in Figure 4-5, have the lowest CVR factors where the non-electric loads, shown in the purple bars in Figure 4-5, have higher CVR factors.

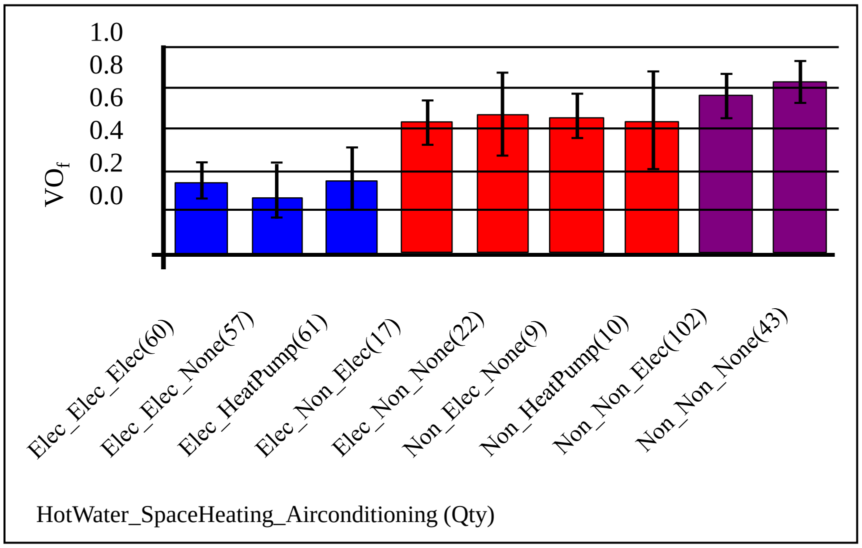


Figure 4-5: Energy Reduction Response to Applied Voltage (%ΔE/%ΔV p.u.)

An example of the possible benefits from voltage optimization can be seen in a study performed by SAIC. Bonneville Power Administration (BPA) developed the Energy Smart Utility Efficiency (ESUE) Voltage Optimization (VO) program. This program incentivizes utilities to improve the efficiency of the distribution system in order to help utilities meet regional goals established by the Northwest Power and Conservation Council's (NWPCC) Sixth Northwest Power Plan. The NWPCC goals for energy efficiency included potential distribution efficiency savings based on the Northwest Energy Efficiency Alliance's (NEEA) Distribution Efficiency Initiative research project completed by SAIC in 2007. [20]

SAIC has performed ESUE studies for seven utilities that included 21 substations and 70 distribution feeders. The results of the ESUE studies show that the majority of substations and associated feeders analyzed could be made more efficient by implementing cost-effective system improvements and operating the voltage level in the lower acceptable voltage range. In most of the cases, more than just adjusting voltage bandwidth was required to achieve the potential energy savings. [21]

Total energy savings was estimated at 1.3 percent and 19,837 MWh/year, where 11.3 percent of the savings were from system loss reductions and 88.7 percent from end-use customer load. The total benefit to cost ratio for all projects was 1.10. This assumes there is a benefit for the reduction of customer load and does not consider the reduction in revenue based on the ESUE program policy. Additional analysis was performed that excluded some of the worst-performing feeders/substations that had individual benefit-to-cost ratios less than 1.0. Total energy savings was estimated at 1.21 percent and 14,534 MWh/year, where 5.2 percent of the savings were from system loss reductions and 94.8 percent from end-use customer load. The total benefit to cost ratio for the subset of projects was 4.32.

[20] Ibid.

[21] "How Utilities Can Better Use Their Distribution Assets," NWPPA E&O Conference, 2011.

For more details on the ESUE study, see Appendix E.

Transmission Efficiency Improvements

A good opportunity to capture transmission loss savings is when new equipment is added to the transmission system. Most utilities agree that transmission projects cannot be cost justified based solely on loss savings. When new transmission expansion plans are developed, the value of future transmission losses (and savings) is included in the cost/benefit assessment of the transmission.

EPRI is currently conducting a study on transmission efficiency[22] that includes input from representatives from transmission owners and operators, vendors, research organizations, members of various public and advisory entities, and EPRI. The collaboration of the participants is needed to demonstrate and evaluate technologies and identify potential for reducing transmission losses and enhancing efficiency. Over 20 utilities and operators of transmission systems are engaged in efficiency projects to help the industry meet the Department of Energy's goal of improving grid efficiency by 40 percent by 2030.

EPRI developed the framework for the analysis, defined the participation of the stakeholders, developed a schedule, and is currently performing the analysis. From six different workshops held in 2009, including more than 320 stakeholders, several areas for improving transmission efficiency were defined:

- Reduce system losses – Including measures such as increasing nominal voltage (new lines or voltage upgrades), dispatch considerations to relieve flows from overloaded or higher-loss lines to less congested and/or lower-loss lines, coordinated voltage control across the system to reduce VAR flow, and other means of controlling power flow.
- Reduce line/equipment losses – Including measures such as low-loss lines and configurations, low-loss transformers, and auxiliary equipment. Superconductivity may also be applicable in some cases.
- Increase system/resource utilization – Optimizing utilization of assets and resources, including right-of-way, materials, labor, time, and dollars.

From the workshops, a further breakdown of seven proposed technologies will be investigated in the EPRI study. Each technology could have a significant impact on losses. See Table 4-3 for a list of the demonstration technologies and some of the benefits of each.

Table 4-3
EPRI Transmission Efficiency Targeted Technologies

Transmission Efficiency Improving Opportunity	Demonstration Technologies	Benefits
Reduce System Losses	Voltage Upgrade/Extra High Voltage (EHV) AC/High Voltage	EHV overlay to allow upgrades & retirements of less efficient voltages. Use HVDC lines where appropriate. Increase

[22] Transmission System Efficiency Technology and Methodology Assessment. EPRI, Palo Alto, CA: 2010. 1020143].

Transmission Efficiency Improving Opportunity	Demonstration Technologies	Benefits
	DC (HVDC)	capacity/decrease losses.
	Coordination Voltage VAR Control	Centralized, coordinated control of bus voltages to allow a flatter voltage profile and minimize reactive power losses.
	Loss Minimization Optimization	Higher efficiencies attained by dispatching generation closer to load or in a way that increases utilization of transmission lines operating at higher voltages while decreasing the load on lower-voltage lines.
Reduce Line/Equipment Losses	Advanced Conductors/ Superconductors/ Low-Loss Design	Lower system losses, increased ampacity, and higher throughput.
	Low-Loss/LEED Substation Equipment & Transformers	Reduce substation power demand and system losses.
Manage Line/System Utilization	Dynamic Rating	Help increase power flow through existing transmission corridors with minimal investment, accelerate integration of renewable resources, improve situational awareness in control centers, reduce losses by redirecting energy to higher voltage lines, and increase grid reliability and safety.
	Smart Transmission	Provides capability to direct power flow to more efficient paths to reduce system losses, relieve congestion, and mitigate loop flow.

Although the EPRI study still continues, the efforts to date have identified a number of promising efficiency-enhancement technologies for transmission systems. Because the electrical power system is essentially a number of interconnected pieces of equipment, shifting to high-efficiency equipment, or components, can significantly contribute to system loss reduction. Nonetheless, results of the demonstration projects thus far reveal that opportunities to reduce system losses by the use of high-efficiency equipment arise if a particular piece of equipment (such as line conductor, transformer, capacitor, or reactor) is to be replaced for other reasons, such as age, failure, or under capacity. Replacing existing equipment just for the sake of loss reduction is seldom justified economically. On the other hand, projects related to increased transmission capacity show that, in some cases, a simple solution such as reconductoring a short line with advanced conductor can boost transmission capability, permitting higher utilization of the existing assets. Further insight and more definite conclusions will be obtained after all the ongoing and upcoming demonstration projects are finalized; however, these results provide a basis on which to start building the case for supporting initiatives to accelerate the massive adoption of these technologies.

5
IMPACT OF NEW TECHNOLOGY ON LOSSES

The electric system grid is dynamic in nature, with constantly evolving technology improvements and enhancements. One consideration for power systems is the impact on losses from technological advancements. The following discussion describes the impact that new technologies could have on losses in transmission and distribution systems.

Advanced Metering

As data from advanced metering becomes integrated in the utility's infrastructure, at both the feeder and substation level, as well as the customer level, the load data can be directly assigned to the computer simulation model. Many of the computer simulation software packages, both transmission and distribution, are expanding to allow for these capabilities. In addition, hourly data, including kW and kvar, can be used to calculate energy and peak system losses. This method can produce more precise results by eliminating estimations of load allocation and provide added granularity in the results. AMI data will increase the complexity of the data management and analysis. The benefits of AMI are more precise knowledge of loadings of specific equipment. For example distribution transformer loading estimates will be more accurate and will include time variability.

Similarly, with advanced metering in place, data is available to help determine and distinguish losses on the transmission system versus losses on the distribution system and more precisely identify substation losses. More advanced metering options will help with measuring end-of-line voltage for monitoring compliance with performance standards and practicing CVR techniques effectively.

High-Voltage Direct Current (HVDC) Transmission

Most of the transmission lines in the North American electric grid are high-voltage alternating current (HVAC) lines. An emerging trend being considered is high-voltage direct current (HVDC) lines because of some of the advantages in efficiency. According to an ABB study[23], HVDC lines provide 25 percent lower line losses, two to five times the capacity of AC lines at similar voltages, and the ability to precisely control the flow of power.

Historically, the costs have been too high for most transmission operators to consider HVDC as an option, except in a few long-distance applications. However, with technological improvements and more economical options becoming available, HVDC may be considered more feasible in the near future.

[23] ABB, "Energy Efficiency in the Power Grid", 2012; http://www.abb.com/cawp/seitp202/64cee3203250d1b7c12572c8003b2b48.aspx

Gas-Insulated Substations

Gas-insulated substations are a possible solution to help reduce losses. Typical substations occupy large tracts of land and are located outside of dense load areas. As a result, lower-voltage lines from substations can go quite a distance before reaching load centers, which increases losses. Gas-insulated substations are encapsulated, with all equipment inside a metal housing, and can be contained in a basement or building close to the load center, which would help in the reduction of losses.

Energy Star Program

The ENERGY STAR program was created in the early 1990s by the United States Environmental Protection Agency (EPA) in an attempt to reduce energy consumption and greenhouse gas emission by power plants. ENERGY STAR has become very popular in the residential and commercial sector and has shown significant improvements with efficiencies in appliances and computer/television technologies. Areas of improvement that might be considered in compliance with ENERGY STAR Certification are obtaining a unity power factor—which would help utility system VAR requirements significantly—and limiting harmonics—which would help reduce losses and release capacity. While this might be a far-sighted observation (more studies and discussions may occur), this is a relevant option to investigate that could have a significant impact on electric system losses.

Distributed Generation

The number of installations of solar, wind, hydro, and other distributed generation (DG) resources will continue to grow, and more impacts will be seen on the electric transmission and distribution system. Incentives from utilities and the government entice prospective developers and commercial and residential customers to install DG resources, and the installations are growing rapidly. Studies have been and are being performed to understand the impacts that DG resources have on capacity, voltage, stability, VAR requirements, losses, and so on. The question is: How should these different types of generation be accounted for in analyzing power systems and in analyzing losses?

In January 2009, SAIC finalized the Distributed Renewable Energy Operating Impacts and Valuation Study for Arizona Public Service (APS). The goal of the study was to determine the potential value of solar distributed energy (DE) technologies for the APS electrical system and to understand the likely operating impacts. Commercial and residential solar systems, residential solar hot water systems, and commercial day lighting systems were the specific solar technologies studied.

The APS study assessed the value that solar DE provides to the transmission and distribution systems by reducing losses. Much of the potential annual saving from solar DE results from APS, avoiding the energy produced from solar DE systems. This reduced energy requirement decreases fuel and purchased-power requirements and brings associated reductions in line losses and annual fixed O&M costs. The study determined annual energy loss savings ranging from 1,829 to 2,031 MWh, in several different cases studied in 2010. For projections for 2025, annual energy loss savings ranged from 18,607 to 407,170 MWh. The full case study is presented in Appendix F.

Electric Cars

Electric plug-in vehicles were just talk a few years ago, but now they are being manufactured and purchased by consumers. The market penetration level for electric cars is low right now, but it is expected that their popularity will continue to grow as gas prices rise. Studies are still being performed to estimate the impact of electric cars on the electric system.[24] There are questions about the system improvements that will be required to meet the needs of electric cars, such as distribution transformer upgrades and line upgrades (conductor size and multi-phasing).

In addition to the impact of charging, some utilities are also evaluating the possibility of vehicle to grid discharging as a source of distributed generation.

Recent studies have shown that significant deployment of distributed generation creates reverse power flow in distribution systems and that bi-directional power flow can have effects on the quality of power supply and voltage levels. Distributed generation may also lead to increased fault currents, malfunction of the network protection system and phase imbalance (specific to single-phase applications).[25]

Losses will be impacted and likely increased due to the addition of load in mostly residential areas, which are radial and single-phase in nature. Adding loads to these areas creates more line current unbalance and increased losses due to heavy loading on distribution equipment. Utilities have just begun investigating the impacts. One possible approach that could help is to begin discussions with local car dealerships (and consumers) to communicate information about purchases of electric cars in the community and be prepared for their impact on the electric system.

Other Emerging Trends

Other notable emerging trends to consider in analyzing energy efficiency include superconductors, thermal monitoring of transmission lines, LEED Certification of Substations, and optimization of asset-replacement schedule. “Right-sizing” equipment to the load should reduce losses.

[24] Gartner, J. & Wheelock, C. (2009). “Research Report: Electric Vehicles on the Grid. Pike Research, LLC.” Retrieved from: http://www.pikeresearch.com/research/smart-energy/electric-vehicles-on-the-grid

[25] Putrus, G.A.; Suwanapingkarl, P.; Johnston, D.; Bentley, E.C.; Narayana, M.; , “Impact of Electric Vehicles on Power Distribution Networks,” *Vehicle Power and Propulsion Conference, 2009. VPPC '09. IEEE* , vol., no., pp. 827–831, 7-10 Sept. 2009 doi: 10.1109/VPPC.2009.5289760

6
EVALUATING COSTS AND BENEFITS

Evaluating the Cost of Losses

Not only are losses significant to the efficiency of an electric system, but they also have quantifiable cost impacts as well. Because power costs differ significantly between utilities, the cost of losses is unique to each utility.

For a utility that owns generation, transmission, and distribution facilities, a kW or kWh reduction on the distribution system can have a value substantially greater than a kW or kWh reduced at the power source when considering the capital cost of capacity to transmit the power.

The value of peak kW reduction is highly dependent on the cost of generating the next kW and the cost of the total plant required to generate and deliver the peak kW. The value of kWh reductions are more directly coupled with the cost of generating the next kWh (such as fuel costs) and the associated line losses from the point where the energy reduction occurs back to the source.

For a utility that is a wholesale buyer of power requirements, the value of reducing peak kW and kWh is equal to the cost of purchased power. Wholesale utilities may have a tiered energy rate and a monthly demand rate. In some cases, a wholesale utility may have a reactive power rate or penalty charge to be considered.

For a wholesale buyer of power requirements, a simple industry-accepted approach from the Rural Utilities Service (RUS)[26] can be used to calculate the cost of losses for a single kW of load (winding) loss or a single kW of no-load (core) loss. The following information is required:

- Average annual system load factor (a three-year average is a good rule of thumb)
- Wholesale power costs – energy and demand
- Annual monthly system peak demand (three years of data is a good rule of thumb)

Using the RUS approach, the cost for 1 kW of peak <u>load</u> losses is calculated as follows:

- Cost of Demand = 1 kW * Demand Rate * Demand Factor
- Cost for Energy = (H * Load Factor^2 + (1-H) * Load Factor) * 1 kW * Energy Rate *8760 hours

Where:

$$\textit{Demand Factor} = \sum\left(\frac{Average\ peak\ for\ each\ month}{System\ Peak}\right)^2$$

[26] Rural Utilities Service, *Guide for the Evaluation of Large Power Transformer Losses*, RUS Bulletin 1724E-301, 2009.

$$Load\ Factor = \frac{kWh\ per\ year}{8760 * peak\ kW}$$

H = Hoebel coefficient – ranges from 0.85 to 0.90. The standard value of 0.9 is generally used.

Using the RUS approach, the cost for 1 kW of peak no-load losses is calculated as follows:

- Cost of Demand = 1 kW * Demand Rate * 12 months
- Cost for Energy = 1 kW * Energy Rate * 8760

To gain a better understanding of how the equations above are used with sample historical data, an example calculation of the cost of losses is presented below for a fictional Utility A.

Table 6-1
Utility A Historical System Data

Month	Peak Load kW			Three-Year Average (kW)	Percent of Average Peak	Percent of Peak Squared
	2009	2010	2011			
January	91,062	120,288	129,791	113,714	98.28%	0.97
February	107,418	128,287	111,412	115,706	100.00%	1.00
March	93,780	94,981	99,514	96,092	83.05%	0.69
April	73,150	90,814	80,788	81,584	70.51%	0.50
May	81,386	82,356	63,966	75,903	65.60%	0.43
June	87,101	86,331	90,331	87,921	75.99%	0.58
July	96,174	88,461	89,915	91,517	79.09%	0.63
August	96,925	99,175	86,619	94,240	81.45%	0.66
September	68,240	87,477	90,756	82,158	71.01%	0.50
October	82,412	80,118	83,626	82,052	70.91%	0.50
November	90,079	92,855	102,385	95,106	82.20%	0.68
December	112,809	103,604	125,900	114,104	98.62%	0.97
System Peak	112,809	128,287	129,791	115,706	100.00%	8.10
Annual MWh Purchased	446,178	468,537	463,945	459,553		
Annual Load Factor	45.15%	41.69%	40.81%	42.55%		

Based on the calculations shown in Table 6-1, the three-year average load factor for Utility A is equal to 42.55 percent, and the demand factor is 8.10.

Assuming that Utility A has an energy rate of $0.0637/kWh and a demand rate of $8.32/kW, and using the equations described above, the annual cost for 1 kW of peak losses are shown in Table 6-2.

Table 6-2
Sample Cost of Losses Calculations

	Load Loss	No-Load Loss
Cost for Demand	$67.43	$99.84
Cost for Energy	$114.72	$558.27
Annual Cost for 1 kW of Peak Losses ($/kW)	**$182.15**	**$658.11**

For each kW of peak load loss calculated for a utility, the load and no-load values calculated can be applied to determine the total cost of losses for the system. This approach does not include other associated costs or benefits that would be included to perform a full cost/benefit analysis. However, it is one component that is factored into a full cost/benefit evaluation. The cost of losses is also included in the economic analysis of conductors and transformer purchases.

Cost/Benefit Analyses

An economic cost/benefit analysis is commonly performed by utilities when evaluating system improvements to reduce electric system losses. As the name suggests, the analysis considers the annual costs of system improvements (including financing costs, if applicable), as well as the benefits in the form of annual cost savings or additional revenue, to achieve the desired goals. The annual costs and benefits are projected over the study period selected to determine an annual net cash flow. The net present value (NPV) of the annual net cash flows is used to evaluate the life-cycle cost of each of the system improvement alternatives that the utility is considering.

For a complete cost/benefit analysis, utilities need to quantify the full costs and benefits associated with capital projects and the reduction of demand and energy requirements. The capital cost of the released capacity does not necessarily appear as a direct immediate cost benefit to the utility. However, the long-range, cumulative effect of kW and kWh reductions on a utility system may reduce the long-range need for capital investment.

The value of a peak kW and kWh reduction can vary widely between utilities for some of the following reasons:

- A substantial difference in dollar of gross utility plant per kW or kWh.
- The operation costs for a utility’s mix of generation used to meet on- and off-peak. requirements
- If a utility is capacity constrained, by either physical plant or contractual requirements.
- Variation in interest rates and taxes. For example, public utilities typically have lower tax burdens and are considered non-profit.

When comparing alternative loss-mitigation strategies, a base case needs to be established based on current utility practices, and each considered alternative is compared to the base case. Some of the factors to consider when performing cost/benefit analyses include:

- The cost to the utility for the next kW purchased (avoided cost)
- The cost to the utility for energy

- The duration of the benefit/cost analysis, such as 20 years
- The initial investment
- Future investments
- Changes in operation and maintenance costs
- Remaining life at the end of the analysis term
- The rate of load growth
- Inflation rate
- Discount rate
- Energy savings
- kW demand reduction
- kVAR demand reduction
- Deferred capital investment
- Renewable energy and investment tax credits
- CO_2 impacts

To gain a better understanding of how a cost/benefit analysis is performed, please see Appendix G for examples of cost/benefit analyses performed by the participating utilities and other utilities to evaluate which loss-mitigation strategies would be economical to pursue.

7
PROVISIONS FOR REACTIVE POWER TARIFFS

Impacts on the T&D System

Reactive power requirements on electric systems lead to reduced power factor, which includes increased current flow, which increases losses and reduces voltage. Reactive power is required by electric motors, transformers, florescent lighting ballasts, and other equipment to be magnetized and startup. Electric current is used to create the magnetic field, which produces the desired work; however, no net energy is transferred to the load. For this reason, reactive power is referred to as "non-working" power, in contrast to real or working power, which uses kilowatts to create heat (resistive load) to produce the desired work. The total or apparent power required by an inductive device is a composite of the following:

- Real power (measured in kilowatts, kW)
- Reactive power, the nonworking power caused by the magnetizing current, required to operate the device (measured in kilovars, kVAR)

Power factor is defined as the ratio of real power to apparent power. An increase in reactive power causes an increase in total apparent power, which results in a lower power factor. Conversely, as the amount of reactive power decreases, the ratio of real power to apparent power (the power factor) approaches 100 percent.

$$\text{Power Factor} = \frac{\text{Real Power}}{\text{Apparent Power}}$$

Reactive power required by inductive loads (loads that require current to create a magnetic field) increase the amount of apparent power in the distribution system, which causes the power factor to decrease. The U.S. Department of Energy developed an excellent fact sheet describing power factor and the effect of reactive (non-working) power on power factor, which is provided in Appendix H.[27] Low power factor reduces the capacity of the electric distribution by increasing the current flow, which causes energy losses to increase. The more reactive power that customers use, the more energy the system loses. Some utilities charge an additional fee to large commercial and industrial customers if their power factor is less than 0.95 to compensate for energy losses and encourage these customers to take corrective action to improve their power factor.

[27] "Reducing Power Factor Cost," Motor Challenge Information Clearinghouse, U.S. Department of Energy, at http://www1.eere.energy.gov/industry/bestpractices/pdfs/mc60405.pdf.

The benefits for utilities in improving power factor include:

- **Loss Reduction:** Resulting from lowering current flow and I^2R losses.
- **Capacity Release:** For example, a 12/16/20-MVA transformer loaded to 18.2 MW at a 90% power factor would be loaded above the top nameplate rating (18.2 MW ÷ 90% = 20.2 MVA). However, at an equivalent demand with a 95% power factor, it would be only 96% loaded (18.2 MW ÷ 95% = 19.2 MVA).
- **Voltage Improvement:** Resulting from lowering current flow.
- **Cost Savings:** The loss reduction results in costs savings based on the annual cost of losses.

Utility customers can also benefit from improving power factor in the form of lower utility bills by eliminating power factor penalties and by reducing I^2R losses inside their facility.

Some widely known strategies for correcting power factor include capacitor placement near the source of the inductive load, minimizing operation of idling or lightly loaded motors, avoiding operation of equipment above rated voltage, and updating standard motors with more energy-efficient motors and operating them near capacity.

Reactive power charges for customers with low power factors (typically larger commercial or industrial classes) can be put into place to help utilities recover cost burdens due to reactive demand contributions from customers and increased system losses. Compensation to generation resources is also included in some rate structures.

There is sensitivity in selecting the “right” penalty charge for customers with low power factors. Too great a penalty could result in customers purchasing expensive machinery and modifying production techniques unnecessarily and could deter customers from requesting service from the utility. However, a charge that is too low would not allow the utility to recover the associated costs and may not provide the stimulus needed to motivate customers to perform corrective measures. Corrective measures are typically associated with capacitor additions to improve power factor for reducing losses at the distribution and transmission levels.

Reactive power pricing “…should encourage efficient and reliable investment in the infrastructure needed to maintain the reliability…” of the electric system. Also, it “…should provide incentives for the reliable and efficient production and consumption of reactive power from the existing available infrastructure, taking into account the opportunity costs of the provision of competing uses of the available resources (such as real power and operating reserves).”[28]

Summary of Reactive Power Tariffs for the Participating Utilities

In June 2008, the New York PSC instituted a proceeding “to identify measures that should be taken to reduce electric system losses and to optimize system operations.”[29] As a first step, the PSC required utilities to submit reports within six months of the June 23 order, “identifying measures to reduce system losses and/or optimize system operations,” including an analysis of

[28] Federal Energy Regulatory Commission (FERC) Staff Report, “Principles for Efficient and Reliable Reactive Power Supply and Consumption,” February 4, 2005 at http://www.ferc.gov/eventcalendar/files/20050310144430-02-04-05-reactive-power.pdf.

[29] New York PSC, Case 07-M-0548, Order dated June 23, 2008.

reactive power provisions and charges contained in the utilities tariffs. To the extent a utility did not have reactive power provisions and rates in its tariffs, it was required to develop such tariffs and file them with its six-month reports.[30]

The participating utilities submitted the six-month reports listed below in response to the PSC order, which were reviewed as part of this study.

- National Grid: "Six-Month Report of Niagara Mohawk Power Corporation d/b/a National Grid"
- Central Hudson Gas & Electric Corporation: "Identifying the Sources of Electric System Losses and the Means of Reducing Them"
- New York State Gas & Electric: "NYSEG and RG&E Loss Reduction Opportunities Report"
- Rochester Gas & Electric: "NYSEG and RG&E Loss Reduction Opportunities Report"
- Consolidated Edison: "Report of Consolidated Edison Company of New York, Inc. on Electric System Line Losses"
- Orange & Rockland: "Report of Orange and Rockland Utilities, Inc. on Electric System Line Losses"
- Long Island Power Authority: "Report for T&D Loss Reduction"[31]

In September 2009, the PSC released its order adopting reactive power tariffs with modifications. The PSC stated:

> Reactive power charges are necessary because they signal to large customers and operators of induction generators the utility's cost of providing them with reactive power. . . . Reducing system reactive power needs reduces costs to all customers by reducing system line losses, increasing the capacity available to transmit real power, and improving voltage profiles on the system.[32]

The PSC implemented the following standards for utilities to use in developing reactive power tariffs:

- Instituted a two-year phase-in plan so that effective October 1, 2010, reactive power charges would apply to customers whose demand in any two of the previous 12 months is 1,000 kW or larger; effective October 1, 2011, this threshold amount was reduced to 500 kW or larger. Utilities may propose to the PSC, with sufficient justification, the application of reactive power charges to customers with lower usage than the 500-kW threshold established in the order.
- Some of the existing utility tariffs stated that reactive power charges would apply to customers whose demand exceeded 500 kW (or applicable threshold amount) for <u>three consecutive months</u>. The PSC required all utility tariffs to specify that reactive power charges would apply to customers whose demands exceeded the threshold demand in <u>any two of the previous 12 months</u>.

[30] New York PSC, Case 08-E-0751, Clarifying Order dated July 17, 2008.
[31] LIPA is not regulated by the PSC but is included as a participating utility in this study.
[32] New York PSC, Case 08-E-0751, Order dated September 22, 2009.

- Reactive power rates shall be based upon the avoided marginal cost to each utility of installing capacitor banks to supply required reactive power. Generally, the rates should reflect the per-unit costs of corrective equipment and applicable carrying charges. The PSC accepted the methodology that each utility used in its December 2008 reports because each methodology was reasonably based on the marginal avoided cost reflective of each utility system's characteristics.
- Reactive power charges can be applied on a peak usage basis (kVAR) or on an hourly usage basis (kVARh). For tariffs to which rates apply on a peak usage basis, reactive power charges shall apply to customers with power factors below 95 percent. For utilities measuring reactive power on an hourly basis, reactive power charges shall apply to customers with power factors below 97 percent.
- Because induction generators consume considerable reactive power, utilities were directed to file reactive power tariff provisions and rates, effective October 1, 2010, applicable to customers with induction generators having a total nameplate rating greater than or equal to 1,000 kW and, effective October 1, 2011, applicable to customers with induction generators having a total nameplate rating greater than or equal to 500 kW.

The PSC stated that "the most effective way to reduce losses resulting from customers' reactive requirements is to install corrective measures at the source of the problem (i.e., at the customers' premises)."[33]

Lastly, in order to monitor customer responses to reactive power tariffs, the PSC's September 2009 order requires each utility to file on October 1st of each year for five years starting in 2010 the number of customers subject to reactive demand charges, the percentage of the utility's total load used by these customers, and the billable kVAR or kVARh over the previous 12-month period.

Table 5-1 summarizes data regarding the reactive power tariffs of the participating electric utilities in New York.

[33] State of New York Public Service Commission, Order Adopting Reactive Power Tariffs With Modifications, September 22, 2009.

Table 5-1
Summary of Reactive Power Tariffs in New York

				Threshold			Induction
Utility	Charge	Basis	Billing Determinant	Power Factor	Demand	Time Period	Generators
Central Hudson Gas & Electric	$0.83 per RkVa	Peak usage	Highest 15-min. integrated kVA of lagging VAR during the month minus 1/3 of the highest 15-min. integrated kW demand	Less than 95%	Above 500 kW (Threshold reduced from 1,000 kW to 500 kW over 2-yr period.)	Demand exceeds threshold amount in any two of the previous 12 months	Charge applies to generators with total nameplate ≥ 500 kW
Consolidated Edison	$1.10 per kVAR	Peak usage	Highest integrated kVA of lagging VAR during the month minus 1/3 of the highestintegrated kW demand	Less than 95%	Above 500 kW (Threshold reduced from 1,000 kW to 300 kW (in 2012) over 3-yr period.)	Demand exceeds threshold amount in any two of the previous 12 months. As of Oct. 2012, will also apply if demand exceeds 300 kW in any month during previous year ending Sept 30.	Charge applies to generators with total nameplate ≥ 500 kW
New York State Gas & Electric	$.00078 per RkVAh	Hourly usage	RkVah in excess of 1/4 metered kWh	Less than 97%	Above 200 kW	Demand exceeds threshold amount in any two of the previous 12 months	
Rochester Gas & Electric	$.00127 per RkVah	Hourly usage	RkVah in excess of 1/4 metered kWh	Less than 97%	Above 500 kW (Threshold reduced from 1,000 kW to 300 kW (in 2012) over 3-yr period.)	Demand exceeds threshold amount in any two of the previous 12 months	
Niagra Mohawk (National Grid)	$0.85 per RkVA for SC-3 (Large General Service ≥ 100 kW); $1.02 per RkVA for SC-3A (Large General Service TOU ≥ 2,000 kW)	Peak usage	Highest 15-min. integrated kVA of lagging VAR during the month minus 1/3 of the highest 15-min. integrated kW demand	Less than 95%	Above 500 kW	Demand exceeds threshold amount in any two of the previous 12 months	
Orange & Rockland	$0.40 per RkVA	Peak usage	Highest 15-min. integrated kVA of lagging VAR during the month minus 1/3 of the highest 15-min. integrated kW demand	Less than 95%	Above 500 kW (Threshold reduced from 1,000 kW to 500 kW over 2-yr period.)	Demand exceeds threshold amount in any two of the previous 12 months	Charge applies to generators with total nameplate ≥ 500 kW
Long Island Power Authority	$0.40 per KVAR for Service Class 2 - MRP (Large General and Industrial Service w/ Multiple Rate Periods); $0.27 per KVAR for Service Class 2H (Building Heating Service), Service Class 2L-VMRP (Voluntary Large Demand Metered Service w/ Multiple Rate Periods), and Service Class 2-L (Large General Service)	Peak usage	15-min. integrated kVA of lagging reactive demand minus 48% of 15-min. integrated kW demand recorded during the same 15-min. period. Customer is billed for maximum Net Reactive Demand recorded for month from 7:00 a.m. through 11:00 p.m., or 100% of maximum Net Reactive Demand recorded from June through Sept., from 7:00 a.m. through 11:00 p.m., during the last 11 months.	Less than 90%	Above 500 kW or Above 145 kW	If demand exceeds 500 kW in any two of the previous 12 months If demand exceeds 145 kW in any summer month (June through Sept.)	Customers with highly fluctuating or large instantaneous demands (welders, x-rays) shall provide batteries, rotating equipment, or other corrective equipment to reduce the inrush current to an amount acceptable to the Authority.

Note: Reactive power demand charges as of February 1, 2012.

Industry Comparison

Research on reactive power customer charges across the industry was completed to have a basis for comparison to the tariffs in place for the participating utilities. The findings are presented below.

FirstEnergy (formerly Allegheny Power) – serving customers in the Midwest and Mid-Atlantic regions (URL)[34]

A kVAR charge is applied to the Customer's kVAR capacity requirement in excess of 25 percent of the Customer's kilowatt capacity.

Billing kVAR $0.40 per kVAR.

Capacity required is the highest metered demand in kVAR established over a 30-minute interval during a billing period.

Reactive meters will be installed when the customer's kilowatt capacity exceeds 200 kilowatts. Kilowatts and kVAR will be computed to the nearest 1/2 kilowatt and kVAR.

PEPCO – serving customers in D.C. and parts of Maryland (URL)[35]

PEPCO does not appear to charge customers for reactive demand, with the exception of time metered rapid transit service accounts.

The monthly billing reactive demand will be the maximum 30-minute integrated coincident kVAR demand of each delivery point served less the kVAR that would be supplied for an 85 percent power factor. A charge of $0.15 per kVAR will be assessed for each kVAR in excess of requirement for 85 percent power factor. The need for reactive metering will be determined by the Company.

Georgia Power – serving customers throughout most of Georgia (URL)[36]

Where there is an indication of a power factor of less than 95 percent lagging, the Company may at its option, install metering equipment to measure Reactive Demand. The Reactive Demand shall be the highest 30-minute kVAR measured during the month. The Excess Reactive Demand shall be kVAR which is in excess of one-third of the measured actual kW in the current month. The Company will bill excess kVAR at the rate of $0.27 per excess kVAR.

[34] www.alleghenypower.com/Tariffs/MD/Attachments/MDRetailTariff.pdf
[35] www.pepco.com/_res/documents/md_tariff.pdf
[36] www.georgiapower.com/pricing/pdf/5.00_PLL-6.pdf

PacifiCorp – serving customers in Utah, Oregon, Washington, California, Wyoming, and Idaho (URL)[37]

General Service 20 kW and Over:

The maximum 15-minute integrated reactive demand in kVA occurring during the month in excess of 40 percent of the maximum measured 15-minute integrated demand in kilowatts occurring during the month will be billed, in addition to the above charges, at 60¢ per kVAR of such excess reactive demand.

Avista – serving customers in Washington and Idaho (URL)[38]

Rate Schedule 21 – large general service

Where customer's kilowatt demand is 50 kW or more, and customer's maximum 15-minute kVAR demand for that month is in excess of 48 percent of the kW demand, customer will pay $0.50 for each kVAR of excess. The kVAR demand may be determined by permanently installed instruments or periodic tests.

Summary

From the review of reactive power tariffs, it appears the participating New York utilities are incorporating reactive demand provisions similar to other utilities across the country. It can even be said that New York is ahead of the game as a result of the PSC's actions requiring all utilities in the state to have reactive power tariffs and specifying guidelines so the application of the tariffs is standard between utilities. Not enough time has elapsed to allow analysis of the impact in New York State.

Documentation regarding customer response to reactive power charges and the effectiveness of reactive power tariffs in reducing power factor costs is sparse and inconsistent in the industry. Some challenges identified in the industry and for the New York utilities include:

- Some reactive power charges in place are not applied consistently or made transparent enough to be able to determine whether the rate structure design is actually motivating customers to perform corrective actions.
- Choosing an optimal reactive demand level requirement can be challenging. There are other unique challenges dealing with real-time control of reactive power resources.
- The penalties may not be steep enough to motivate customers with low load factors to take corrective action.

Also, providing knowledge to customers with large inductive loads on ways to improve power factor on the customer side and the impact of reactive power requirements on the electric system and other served customers is also beneficial.

Time will show whether provisions for reactive power tariffs are having a positive impact for the utility. In order to monitor the effectiveness of reactive power tariffs in New York, the PSC is

[37] www.pacificpower.net/content/dam/pacific_power/doc/About_Us/Rates_Regulation/California/Approved_Tariffs/Rate_Schedules/General_Service_20_kW_and_Over.pdf
[38] http://www.avistautilities.com/services/energypricing/wa/elect/Documents/Wa_E_2Calc_NonRes_bills_12-01-10.pdf

requiring each utility to file—on an annual basis for five years starting in 2010—data regarding the number of customers subject to reactive power tariffs, the percentage of the utility's load used by these customers, and the amount of reactive power consumed each year. Analyzing this data will provide useful information regarding the effectiveness of reactive power tariff provisions on improving power factor and reducing energy losses.

8
SUMMARY

This report confirms that New York utilities are using standard industry practices in calculating system losses and that there is not a single best practice that can be followed by all utilities. Loss-mitigation strategies being performed by the utilities, as well as reactive demand tariff provisions, are all within normal industry practices as well. While there are some approaches to loss reduction that can be applied system-wide, such as load balancing and power-factor correction, most efficiency improvements are evaluated on a case-by-case basis.

EPRI has been involved in the transmission and distribution energy efficiency initiative by hosting regional workshops, leading the Green Network Project, forming the Transmission Efficiency Leadership Team (ELT), working in the U.S. and overseas, performing pilot studies, and working with NYSERDA in this assessment of transmission and distribution losses. With the output of these initiatives, some new and updated information on measures to reduce losses may surface and shed new light on various economical choices that were only previously speculated for both transmission and distribution.

Many estimations and generalizations must still be used when performing loss studies. With additional research and better metering down to the feeder level, unknowns can be better understood, and the loss-calculation methodology can be refined, which will provide guidance in determining how specific the loss calculations need to be to provide realistic loss values. Advanced metering infrastructure (AMI) and Smart Grid deployments will help gather additional information needed to perform more detailed analysis. With this additional information, detailed analyses can be performed, which will allow the loss-calculation methodologies to be optimized so that the best results can be achieved at minimal costs.

Input from participating utilities, EPRI, SAIC, and NYSERDA at the project workshop and throughout the project helped shape and determine some leading practices in calculating electric system losses. Table 8-1 summarizes options for calculating losses that might benefit the participating utilities in performing future loss studies, gaining precision in calculations, and evaluating losses across the state in a consistent manner.

Table 8-1
Beneficial Industry Practices

Approach	Benefits	Requirement
Separate losses into technical and non-technical categories, and identify the cause and type of losses.	• Aide in targeting sources of system losses and developing appropriate loss-mitigation strategies. • Better tracking and documentation for specific loss reduction improvements. • Document energy savings (in specific areas) so utilities can be properly credited for energy efficiency claims.	• Establish reporting categories. • Additional calculation methods, data, and/or metering may be required.
Install metering down to the distribution feeder level that captures kW, kVAR, kWh, kVARh.	• Provide necessary information to validate models and assumptions. • Identify target areas for loss improvements.	• Adjust loss-calculation methods to eliminate assumptions and use actual metered data. • Additional metering and/or update to current metering technologies. • Additional expense.
Move toward hourly transmission load flows or evaluating multiple load levels for various time periods (typically seasonal) in calculating transmission losses.	• Hourly modeling provides better representation of operating conditions at different load levels and different times of the year.	• May require updated software. • Additional modeling of system components. • Additional metering. • Additional expense.
Obtain more detailed system information—for example, using a GIS/mapping system for identifying primary and/or secondary facilities.	• Reduce use of assumptions in loss calculations and develop more detailed engineering models. • Identify specific areas that will benefit from loss reduction where sampling cannot accomplish this.	• May require updates to software. • Additional effort to collect system facility data, if not already recorded. • Additional expense to collect system data.

A recent EPRI study[39] found that most candidate projects involving reconductoring and advanced technologies cannot be justified solely on efficiency savings. The report further concluded that efficiency is typically a secondary or tertiary benefit to capacity and reliability enhancement for these candidate projects.

Other methodologies that can reduce energy use, but are typically not cost-justified by loss reduction alone, include:

1. Reducing end-use loads through demand management and energy efficiency programs for utility customers, such as window replacement, direct load control, insulating homes, and

[39] *Transmission System Efficiency Technology and Methodology Assessment.* EPRI, Palo Alto, CA: 2010. 1020143.

more efficient appliances. These methods reduce load and have only a minor impact on loss reduction.

2. Implementing voltage optimization (VO) or conservation voltage reduction (CVR). Not traditionally considered part of transmission and distribution loss-reduction methods, CVR has shown in recent studies that reducing voltage can reduce demand and energy consumption without impact to customers. Voltage optimization, which is a technique that first "tunes" the distribution system by implementing system improvements and then applies voltage reduction, increases the amount that the voltage can be reduced for most feeders, thereby increasing energy reduction, and can reduce losses by two to four times as compared to just lowering the voltage. The additional loss reduction comes from the no-load losses in the distribution transformers and from implementing system improvements to tune the distribution system, in addition to the minor reduction in line loss from reducing the end-use load consumption. Voltage optimization is not strictly T&D efficiency, but many of the same approaches to analyzing losses and T&D efficiency apply to voltage optimization. It has the potential for much larger energy savings than loss reduction.
3. Reconductoring of primary or secondary conductors.
4. Multi-phasing of single-phase primary lines.
5. Installing new feeders or substations.

Distinguishing the cause and type of losses helps in developing appropriate strategies to mitigate them. In evaluating loss-reduction measures, it is important to calculate the costs and benefits associated with the system improvements on a case-by-case basis. Utilities can identify areas of the electric system that might have a higher potential for loss reduction and perform specific analysis for these systems to determine whether system improvements can be cost-effective in reducing losses.

From the review of reactive power tariffs, it appears that the participating New York utilities are incorporating reactive demand provisions similar to other utilities across the country. Documentation regarding the impact of implementing reactive power charges to improve power factor and reduce losses is sparse and inconsistent in the industry. Some challenges identified in the industry:

- Some rates in place are not applied consistently or made transparent enough to be able to determine whether the design of the rate structure is actually motivating customers to perform corrective actions.
- Choosing an optimal reactive demand level requirement can be challenging. There are other unique challenges dealing with real-time control of reactive power resources.
- The penalties may not be steep enough to motivate the applicable customers to take action.

Industry research, such as EPRI's Distribution Green Circuits and Transmission Efficiency programs and the Northwest Energy Efficiency Alliance's Distribution Efficiency Initiative, as well as the studies performed by the New York utilities, demonstrate that the efficiency of the power-delivery system can be improved. If the main criterion for economic justification is the marginal cost of energy, these studies tend to show that many loss reduction initiatives cannot be cost-justified. If ancillary benefits such as carbon credits or power quality impacts are considered, more projects are justifiable. Projects with multiple benefits are also more likely to have advantageous benefit/cost ratios. One example is voltage optimization where improvement options like phase balancing can help reduce losses and improve the performance of voltage optimization. For targeted areas, loss reduction can often be economically justified by implementing changes in the way the system is operated—such as voltage set points and capacitor settings.

A
SUMMARY OF UTILITY DATA

Following is a summary of data submitted by utilities in New York in the six-month reports required by the PSC in its order dated June 23, 2008, establishing an Energy Efficiency Portfolio Standard in the State of New York (Case 07-M-0548). Reports were submitted by the following utilities:

Central Hudson Gas & Electric Corp.

Consolidated Edison Co. of New York, Inc.

New York State Electric & Gas Corporation

Rochester Gas & Electric Corporation

Orange and Rockland Utilities, Inc.

Long Island Power Authority

New York Power Authority

Niagara Mohawk Power Corporation (National Grid)

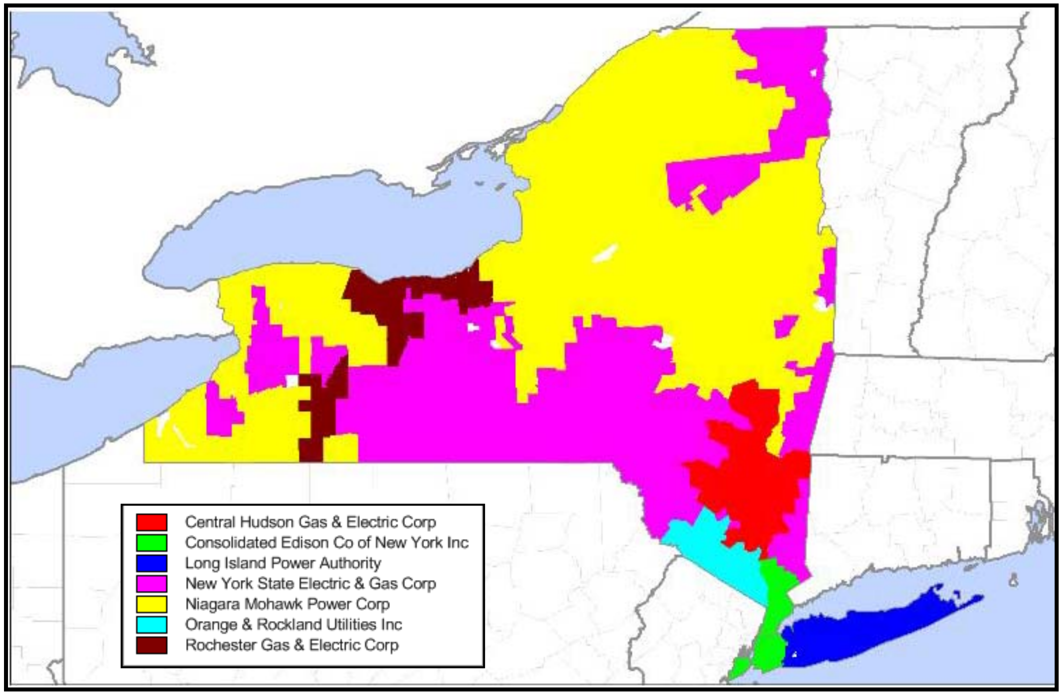


Figure 8-1: Location of Participating Utilities

Table A-2
Evaluation Comparison

	Utility A
System Statistics	2007 Peak – 1,185 MW Customers – 300,000 2007 Losses – 6.73% Transmission 345 kV – 76 miles 115 kV – 245 miles 69 kV – 294 miles Distribution 34.5 kV – 69 miles 13.8 kV – 6,830 miles 4 kV – 2,832 miles
Last Full Loss Study	2010 based on 2007 Losses
Peak Losses Versus Annual Energy Losses	Annual energy losses from loss factor equation and calculated peak losses. Hoebel Coefficient method used. Loss Factors for each voltage level. The following are the energy loss factors: • Transmission: 1.02071 • Primary Substation: 1.03205 • Primary Lines: 1.05489 • Secondary: 1.09042
Calculation Inputs/Other	A loss model, in Excel, was used to house all of the calculations for primary and secondary losses, transformers, conductors MWH generation – MWH sales = losses.
Total Transmission Losses	2.03% or 30.2% of total losses (broken down into voltage classes).
Transmission Losses Calculation Method/Inputs	PSLF- peak load flows – conductors only. Load factors developed for each voltage level.
Substations	0.9% or 13.1% of total losses (<u>separate</u> from transmission losses).
Substation Transformer Losses Calculation Method/Inputs	Peak loading, manufacturer test reports, and loss factor. Core losses held constant.
Total Distribution	3.9% or 56.8% of total losses.
Primary Distribution	1.7% or 24.7% of total losses (<u>included</u> in total distribution losses above) conductors and distribution transformers.
Secondary Distribution	2.2% or 32.1% of total losses (<u>included</u> in total distribution losses above) conductors (secondary and services).
Unaccounted For Category (theft, metering, etc.)	NONE Reconciliation of kW and kWh sales by voltage level was done by adjusting the initial loss factor estimates until the mismatch or difference was eliminated.

	Utility A
Distribution Losses Calculation Method	WindMil for primary distribution peak losses for a sample of circuits and then extrapolated to represent entire distribution system. Secondary and distribution transformers not included in model. Distribution transformer losses calculated in spreadsheet with assumption on # of customers and loading and test reports – core losses held constant. Secondary and service drop losses estimated in spreadsheet based on lengths, size, and loading.
Loss Mitigation Strategies	Evaluated cost/benefit: • Reconductor transmission line • Install sub capacitor bank • Convert three phase circuit from 4.16 kV to 13.8 kV • Convert single-phase spur line from 2.4 kV to 7.9 kV • Poly-phase a single-phase spur line • Replace pole-top transformers to lower impedance xfmrs • Switched distribution capacitors • Transformer load management • New substation transformer None of them proved to be economical. The following are currently underway: • Consideration of I^2R losses in transformer purchases and in distribution conductors • Purchase DOE distribution transformers • Capacitor Placement • Feeder/Load Balancing

	Utility B
System Statistics	2006 Peak – 1,617 MW Customers – 300,000 2007 Losses – 4.64% Transmission 345 kV, 138 kV, 69 kV, 34.5 kV – 540 miles Distribution 34.5 kV, 13.2 kV, 4 kV – 5,600 miles
Last Full Loss Study	2008 based on 2007 losses
Peak Losses Versus Annual Energy Losses	Annual energy losses from loss factor equation and calculated peak losses. Hoebel Coefficient method: Loss Factor = 0.2913 Load Factor = 0.48

	Utility B
Calculation Inputs/Other	Losses determined on monthly basis: Transmission Losses = Total Energy Send out (minus) Substation Output Energy Distribution Losses = Total Losses (minus) Transmission Losses Total Losses = Total Send out (minus) Billed Sales Three types of metering used to get data for losses: inter-utility and net generation; substation output; customer billing.
Total Transmission Losses	1.70% or 36.6% of total losses (broken down into voltage classes) – includes substation transformer losses.
Transmission Losses Calculation Method/Inputs	PSS/E – peak load flows – conductors only. *Dielectric*, I^2R
Substations	0.76% or 16.5% of total losses (included in transmission losses above).
Substation Transformer Losses Calculation Method/Inputs	Peak kW x Transformer Adjustment for Peak Load (TAPL) ^2 x Loss Factor. No-load losses from manufacturer's test reports..
Total Distribution	2.94% or 63.4% of total losses
Primary Distribution	2.53% or 54.5% of total losses (included in total distribution losses above) – broken down by voltage levels – includes conductors and distribution transformers.
Secondary Distribution	0.41% or 8.8% of total losses (included in total distribution losses above).
Unaccounted For Category (theft, metering, etc.)	Transmission – 0.33% or 7.1% of total losses (included in transmission losses above). Distribution – 0.41% or 8.8% of total losses (included in total distribution losses above).
Distribution Losses Calculation Method	Distributed Engineering Workstation (DEW) software for distribution (model contains primary to distribution transformers). Peak kW x loss factor for distribution primary losses. Full load loss x Transformer Load Factor (TLF)^2 x time for distribution transformer losses (where peak losses from DEW load flows). Street lighting use = # of lights x 12 hrs of operation x light wattage. Secondary, station service, and unaccounted for losses are difference between total measured losses by category and sum of calculated losses.
Loss Mitigation Strategies	Evaluated cost/benefit: • Transmission line reconductor • Install capacitors (transmission level) • Substation transformer upgrades • Distribution phase balancing • Install capacitors (distribution level) • Single-phase to three-phase distribution line conversions • Voltage conversion (distribution level) • New distribution circuit • Distribution line reconductor The following are currently underway: • Phase balancing, capacitor installations (distribution), single-phase line conversions. • In the past, transmission line conversions led to decrease in losses significantly. • Investigating Optimal Power Flow – Real-time reactive power management.

	Utility C
System Statistics	2011 peak – 13,189 MW Customers – 3.25 million 2007 Losses – 6.64% Transmission & Distribution 500 kV, 345 kV, 138 kV, 69 kV – 998 miles Distribution 33 kV, 27 kV, 13 kV, 4 kV 63,025 miles
Last Full Loss Study	2008 based on 2007 losses
Peak Losses Versus Annual Energy Losses	Annual energy losses from loss factor equation and calculated peak losses. System loss factor = 0.325
Calculation Inputs/Other	Additional losses were added in due to contingency operations of networks.
Total Transmission Losses	1.75% or 26.4% of total losses (broken down into voltage classes).
Transmission Losses Calculation Method/Inputs	*PSS/E – peak load flows* *conductors only* *Dielectric, I^2R, Corona (345 kV only)*
Substations	1.07% or 16.1% of total losses (<u>included</u> in transmission losses above).
Substation Transformer Losses Calculation Method/Inputs	Manufacturer's test reports for full and no-load losses, with 105% voltage rating used to calculate no-load losses.
Total Distribution	4.06% or 63.8% of total losses *Dielectric, I^2R*
Primary Distribution	2.89% or 43.5% of total losses (<u>included</u> in total distribution losses above – conductors & distribution transformers)
Secondary Distribution	1.17% Or 17.6% of total losses (<u>included</u> in total distribution losses above – conductors & metering). UG on the network system has capacity factor of 57.6%. OH on the network system has capacity factor of 68.2%.
Unaccounted For Category (theft, metering, etc.)	0.83% (theft = 0.16%, metering = 0.18%, and other = 0.49%).
Distribution Losses Calculation Method	PVL (in house distribution load flow software) used in loss study to get current through different conductor/cables sizes on the distribution modeled. Property records used to determine conductor/cable lengths for the loss calculations. Does not contain all distribution and only primary down to distribution transformers. Distribution transformer losses calculated from test reports and number of transformers. Secondary losses determined from average normal loading of distribution transformers, and conductor/cable sizes per transformer kVA size.

	Utility C
Loss Mitigation Strategies	Evaluated cost/benefit: • Distribution phase balancing • Install capacitors (distribution level) • Single-phase to three-phase distribution line conversions • New distribution circuit • Distribution line reconductor • Transmission conductor/cable replacement • Substation equipment replacement • Transmission system operation methods The following are currently underway: • PILC cable replacement program. • Install capacitors in substations. • Migrate smaller customer installations to spot networks. • Standard conductor sizing with standardized ratings and loading criteria. • DOE transformer installations. • Smart Grid 3G System. • Network split at Yorkville. • Conservation voltage reduction (CVR). • Capacitor placement on non-network area of distribution system. • Distribution phase balancing. • Theft-detection program. • New LEED certified substation. • Investigating Optimal Power Flow – Real-time reactive power management.

	Utility D
System Statistics	2006 Peak – 3,405 MW Losses - ~ 3% (From Ventyx Velocity Suite Online (VSO)) Transmission 765 kV – 155 miles 345 kV – 908 miles 230 kV – 336 miles 115 kV – 53 miles
Last Full Loss Study	2008 based on 2007 losses
Peak Losses Versus Annual Energy Losses	Annual energy losses <u>not</u> calculated for voltage classes, just system-wide.
Calculation Inputs/Other	Supply in – deliveries = annual energy losses.

	Utility D
Total Transmission Losses	Losses - ~ 3% (1) Broken down into voltage classes – include conductors, GSU transformers, and substation transformer . Peak Losses only
Transmission Losses Calculation Method/Inputs	PSS/E – peak load flows – conductors, GSU and substation transformers. For the Zone D (115 kV) system a separate model was developed and an hourly analysis was performed using revenue metering data.
Substations	Included in Transmission Losses above.
Substation Transformer Losses Calculation Method/Inputs	Peak load flows with transmission model.
Total Distribution	NONE
Primary Distribution	NONE
Secondary Distribution	NONE
Unaccounted For Category (theft, metering, etc.)	NONE
Distribution Losses Calculation Method	N/A
Loss Mitigation Strategies	The following are currently being done: • Participating in Interregional Reactive Power Management (EPRI project 39) – evaluating voltage controls. • Participating in Efficient T&D Systems for a Low Carbon Future (EPRI project 172) – energy efficiency at generating facilities. • Transmission voltage conversion or reconductoring being investigated for aging infrastructure. • Investigating Optimal Power Flow – Real-time reactive power management.

	Utility E
System Statistics	2011 Peak – 3,346 MW Customers – 878,000 1998 Losses – 10.0% Transmission 345 kV – 533 miles 230 kV – 233 miles 115 kV – 1398 miles 46 kV – 675 miles 34.5 kV – 1,692 miles Distribution 31,122 miles where 35 kV is 15%, 12 kV is 35%, and 5 kV is 50%.
Last Full Loss Study	1998 (percentages shown reflect 2007 estimates though).
Peak Losses Versus Annual Energy Losses	Annual energy losses from loss factor equation and calculated peak losses. Hoebel Coefficient method Load Factor = 0.64

	Utility E
Calculation Inputs/Other	Loss calculations from full 1998 study used as starting point for 2007 estimates. Metered purchases – sales = annual energy losses.
Total Transmission Losses	5.76% or 57.6% of total losses (broken down into voltage classes) – including Bulk Power transmission, Bulk Power substations, Regional Transmission, Regional Substations, Substations, and Distribution Substations. Generator Step-Up units not included.
Transmission Losses Calculation Method/Inputs	PSS/E – peak load flows.
Substations	1.99% or 19.9% of total losses (<u>included</u> in transmission losses above) – Bulk Power substations, Regional Substations, Substations, Distribution Substations.
Substation Transformer Losses Calculation Method/Inputs	Database of transformers, core and coil losses obtained from manufacturer test reports; load losses at nameplate were extrapolated to reflect actual load reads at each substation.
Total Distribution	4.56% or 45.6% of total losses.
Primary Distribution	4.27% or 42.7% of total losses (<u>included</u> in total distribution losses above – conductors & equipment).
Secondary Distribution	0.29% or 2.9% of total losses (<u>included</u> in total distribution losses above – secondary & services).
Unaccounted For Category (theft, metering, etc.)	From the 1998 study, the following values were calculated: • Unmetered Company Use – 21,000 MWH • Customer Meter Inaccuracies – 18,000 MWH • Theft of Service – 10,000 MWH • Interchange Metering – 2,000 MWH Total = 51,000 MWH These categories were not accounted for in the updated 2007 loss calculations.
Distribution Losses Calculation Method	In-house Primary Circuit Analysis (PCA) software used to calculate peak losses on a sample of primary, secondary, and service drops and extrapolated to represent entire distribution system. Distribution transformer losses were calculated from Transformer Load Management (TLM) database using load factor (62.4%) to calculate core and load losses.

	Utility E
Loss Mitigation Strategies	Evaluated cost/benefit: • Review/revise planning criteria for capacitor placement on transmission and distribution. • Asset management. • Switched capacitors. • VAR compensation, SVCs. • Line reconductor. • Use of trapezoidal conductor. • Superconductor. • PILC replacement. • Distribution transformer sizing, removal of unused, replacement of underutilized, DOE standards. • Substation transformer purchasing criteria review, sizing, tap changing. • Transmission and distribution voltage conversion. • Review guidelines for new secondary installation and replacements for sizing. • Distribution primary and secondary engineering models. • Distribution line configuration and spacing. • AMI. • Distribution system control points. • Theft detection. • Infrared surveying. • Transmission retention. • DG VAR support. • Low corona hardware and testing. • Phase shifting transformers. The following are currently underway: • Seasonally bypassing reactors. • Flexible AC transmission system. • HVDC. • Secondary network monitoring. • EPRI Green Circuits initiative. • Smart Grid. • Phase balancing. • Phase ID program. • Distribution circuit optimization. • Standardized distribution transformer purchasing (DOE), adding capacitors to achieve 97% PF (Distribution). • Capacitor installation and studies for transmission.

	Utility F
System Statistics	2011 Peak – 1,752 MW Customers – 367,000 1998 Losses – 3.8% Transmission 115 kV – 117 miles 34.5 kV – 559 miles Distribution 7,597 miles where 35 kV is 2%, 12 kV is 26%, and 5 kV is 72%.
Last Full Loss Study	1998 (percentages shown reflect 2007 estimates though).
Peak Losses Versus Annual Energy Losses	Annual energy losses from loss factor equation and calculated peak losses. Hoebel Coefficient method Load Factor = 0.55
Calculation Inputs/Other	Loss calculations from full 1998 study used as starting point for 2007 estimates. Metered purchases – sales = annual energy losses
Total Transmission Losses	1.9% or 50% of total losses.
Transmission Losses Calculation Method/Inputs	PSS/E – peak load flows.
Substations	Not presented separately, but included in distribution losses.
Substation Transformer Losses Calculation Method/Inputs	Database of transformers, core and coil losses obtained from manufacturer test reports; load losses at nameplate were extrapolated to reflect actual load reads at each substation.
Total Distribution	1.9% or 50% of total losses.
Primary Distribution	0.6% or 15.8% of total losses (included in total distribution losses above).
Secondary Distribution	1.3% or 34.2% of total losses (included in total distribution losses above).
Unaccounted For Category (theft, metering, etc.)	Unaccounted for losses were included in the full 1998 Loss Study, but not in the 2007 update.
Distribution Losses Calculation Method	In-house Primary Circuit Analysis (PCA) software used to calculate peak losses on a sample of primary, secondary, and service drops and extrapolated to represent entire distribution system. Distribution transformer losses were calculated from TLM database using load factor (62.4%) to calculate core and load losses.

	Utility F
Loss Mitigation Strategies	Evaluated cost/benefit: • Review/revise planning criteria for capacitor placement on transmission and distribution. • Asset management. • Switched capacitors. • VAR compensation, SVCs. • Line reconductor. • Use of trapezoidal conductor. • Superconductor. • PILC replacement. • Distribution transformer sizing, removal of unused, replacement of underutilized, DOE standards. • Substation transformer purchasing criteria review, sizing, tap changing. • Transmission and distribution voltage conversion. • Review guidelines for new secondary installation and replacements for sizing. • Distribution primary and secondary engineering models. • Distribution line configuration and spacing. • AMI. • Distribution system control points. • Theft detection. • Infrared surveying . • Transmission retention. • DG VAR support. • Low corona hardware and testing. • Phase shifting transformers. • Seasonally bypassing reactors. • Flexible AC transmission system. • HVDC. The following are currently underway: • Secondary network monitoring. • EPRI Green Circuits initiative. • Smart Grid. • Phase balancing. • Phase ID program. • Distribution circuit optimization. • Standardized distribution transformer purchasing (DOE). • Capacitor installation and studies for transmission.

	Utility G
System Statistics	2006 Peak – 6,754 MW Customers – 1.6 Million 2007 Losses – 9.8% Transmission 4,540 miles of sub-transmission 6,000 miles of transmission Distribution 41,800 miles of distribution
Last Full Loss Study	2004 (percentages shown reflect 2007 estimates though).
Peak Losses Versus Annual Energy Losses	Annual energy losses from loss factor equation and calculated peak losses.
Calculation Inputs/Other	Revenue metering is the primary source for load or the NY Energy Management System (EMS). Load In (including NYISO NMPC estimated losses) – sales = annual energy losses. Expansion Factors calculated from 2004 Study and used to estimate 2007 losses.
Total Transmission Losses	Transmission Expansion Factor = 0.021 5.8% or 59.4% of total losses (transmission) Subtransmission: 27% of sales estimated to pass through sub-transmission 0.7% or 7.1% of total losses (sub-transmission including transformers – 15 kV to 115 kV)
Transmission Losses Calculation Method/Inputs	PSS/E –conductors only. 12 snap-shots were taken at various on/off peak periods.
Substations	Not presented separately but included in sub-transmission losses.
Substation Transformer Losses Calculation Method/Inputs	Based on NY Energy Management System (EMS) sampled data on an hourly basis. Peak loading, manufacturer test reports. No load losses estimated by average no-load loss for range of transformer voltages and sizes and multiplying the results by the number of transformers in each category.
Total Distribution	3.3% or 33.6% of total losses.
Primary Distribution	Primary Expansion Factor = 0.014 1.1% or 10.9% of total losses (<u>included</u> in total distribution losses above) – conductors only.
Secondary Distribution	Secondary Exp. Factor = 0.021 Transformer core losses estimated to be 57% of secondary losses. 2.2% or 22.7% of total losses (<u>included</u> in total distribution losses above) includes distribution transformers.
Unaccounted For Category (theft, metering, etc.)	NONE Trued up in measured categories.

	Utility G
Distribution Losses Calculation Method	CYMDIST for peak distribution losses – conductors only, sampled data (16 ckts). Distribution transformer losses based on average losses and manufacturer test reports, includes load and no-load losses. Secondary losses were based on number and size of distribution transformers connected to feeders analyzed, as well as typical wire configurations chosen based on size of transformer.
Loss Mitigation Strategies	Evaluated cost/benefit: • Distribution voltage conversion. • Distribution line reconductor. • Phase balancing. • Single-phase line conversion. • Distribution transformer sizing. • Installing DOE compliant distribution transformers. • Review distribution substation transformer purchasing criteria. • Distribution line capacitors. • Shunt compensation at transmission level. • Transmission line reconductor. • Increasing conductor size of an approved transmission project. • AMI. The following are currently underway: • Phase balancing pilot (1 of the circuits is part of the EPRI Green Circuits project). • Distribution capacitor placement. • Installing DOE transformers. • Installation of shunt compensation and Investigating Optimal Power Flow – Real-time reactive power management. • Conservation voltage reduction pilot (CVR).

	Utility H
System Statistics	2007 Peak – 5,256 MW Customers – 1.1 Million 2007 Losses – 6.37% Transmission 1,292 miles of transmission and sub-transmission (345 kV, 138 kV, 69 kV, 33 kV, 23 kV) Distribution 13,611 miles of distribution (13 kV and 4 kV)
Last Full Loss Study	2008 based on 2007 losses.
Peak Losses Versus Annual Energy Losses	Annual energy losses were calculated using peak demand losses and a load-duration curve. For transmission, the losses calculated from the load snapshots were used with the load-duration curve to calculate annual energy losses. Load-duration curve shows the average percent energy at each delivery voltage level for each hour of the year.

	Utility H
Calculation Inputs/Other	Metered purchases – sales = annual energy losses
Total Transmission Losses	1.5% or 23.5% of total losses (transmission). (broken down by voltage classes – includes lines step-up/down transformers at transmission level voltages). Subtransmission: 0.13% or 1.9% of total losses (subtransmission).
Transmission Losses Calculation Method/Inputs	PSS/E – conductors and transformers. 8 snap-shots were taken representing different loading levels.
Substations	Percentage of losses not presented separately but losses were calculated by voltage level. Calculated losses included in transmission losses.
Substation Transformer Losses Calculation Method/Inputs	Load losses calculated in load flow model for transmission level transformer step-up/down units. No-load losses calculated separately from manufacturer test reports. Distribution substation transformer losses were calculated using the Area Load Forecast (ALF) in-house tool and manufacturer test reports.
Total Distribution	3.89% or 60.83% of total losses.
Primary Distribution	1.39% or 21.7% of total losses (included in total distribution losses above) – conductors only.
Secondary Distribution	2.50% or 39.1% of total losses (secondary, services, distribution transformers, metering).
Unaccounted For Category (theft, metering, etc.)	0.88% or 13.8% of total losses (theft, metering errors, etc.).
Distribution Losses Calculation Method	Distribution primary conductor/cable losses were calculated using CYMEDIST. 60% of the distribution system was modeled for a sampling technique (530 feeders). Losses were calculated at the coincident summer peak. From this an average watt loss per mile was determined and used to calculate losses for the other 365 feeders. Distribution transformers were not modeled. Core losses were calculated from manufacturer test reports. A transformer load monitored computer (TLM) program was used to determine the transformer load losses. A secondary conductor of 1/0 triplex was assumed as the typical size. Historical data provided a basis for estimated lengths. I^2R losses were calculated based on typical distribution transformer loading for residential loads. The losses were extrapolated out to reflect the rest of the secondary system. Service losses were calculated using typical OH size of #4 and 1/0 AL and typical UG size of 1/0 and 3/0 AL. Historical data provided average length of services, and the number of residential meters was used as a base to determine the amount of wire that is on the system. Resistance per foot of the wire sizes and the estimated lengths of services were used to calculate losses. Meter losses were accounted for.

	Utility H
Loss Mitigation Strategies	Evaluated cost/benefit: • Transmission/Sub-transmission o New 345 kV backbone. o New superconductor backbone. o New HVDC backbone. o 69kV reconductoring/undergrounding. o Load transfers. o Undergrounding new transmission circuits. o North shore 138 kV loop, south shore 138 kV loop, conversions. o Transformer replacements. • Distribution o Load balancing. o Replace inefficient distribution substation transformers. o Install new and efficient distribution substation transformers. o Economic conductor. o 4 kV conversion to 13 kV. o Split higher loaded circuits. o Conversion of some overhead primary to underground. The following are currently underway: • Load balancing. • Switched capacitor additions on the distribution system. • Buying low-loss (DOE) distribution transformers. • Use larger conductors when economically justified.

B

DISTRIBUTION LOSS CALCULATIONS AND EQUATIONS

Load and Loss Factors

Electric system losses are highest during peak conditions. However, approximately 70 percent of the energy losses occur off peak. Therefore, factors that represent the relationship between peak losses and average losses are helpful in determining electric system losses. The loss factor and load factor are similar in that they both describe the relationship between average and peak conditions. The load factor is calculated by dividing the average load by the peak load, while the average load is determined by dividing the energy over a period by the time of the period.

$$LDF = \frac{kWh}{kW_{peak}}\left(\frac{1}{T}\right) \qquad \textbf{Eq. 1}$$

Where

LDF = Load factor

kWh = Energy in kilowatt-hours for a given study period

kW_{peak} = Peak load that occurs within the study period

T = Duration of study period, 8,760 hours for annual analysis

The loss factor is defined as the ratio of the average power loss to the peak power loss, or in other words, kWh losses divided by the hours over study period, divided by the peak kW losses. However, energy losses are typically not directly calculated, and the loss factor is used to calculate energy losses over a period of time based on peak loading loss studies for that same period.

The loss factor can be calculated using data that is commonly available. Loss factors are generally calculated for types of equipment and voltage class. The loss factor can be calculated as

$$LSF = \frac{\sum_{n=1}^{T} kW_n{}^2}{kWpk^2}\left(\frac{1}{T}\right) \qquad \textbf{Eq. 2}$$

Where

LSF = Loss factor

kW = Demand for each hour

$kWpk$ = Peak demand that occurred during the study period

T = Duration of study period, 8,760 hours for annual analysis

Eq. 2 requires hourly load data for the duration of the study period, which may not be available. Another way to calculate the loss factor is by using the load factor.

Loss factor is then calculated as

$$LSF = \left(LDF^2 \times K\right) + \left(LDF \times [1 - K]\right) \qquad \textbf{Eq. 3}$$

Where

LSF = Loss factor

LDF = Load factor

K = Ranges between 1 and 0.7
Distribution transformers K = 0.85
Residential feeders K = 0.9

Note that the loss factor and load factor are dimensionless. This equation is sometimes referred to as the *Hoebel coefficient method*, where K is the Hoebel coefficient.

Substation Transformers

No-load losses (NLL) can be calculated using manufacturer's data for each substation transformer rather than by sampling substation transformers. Impedance values typically range greatly between transformers, even those of comparable size ratings and of the same manufacturer and vintage. Utilities will generally have the transformer test data for each unit. In addition, the average applied voltage versus the nameplate voltage ($V_{Nameplate}$) is taken into account because no-load losses are a function of the applied voltage ($V_{Applied}$) squared.

$$NLL = \frac{NLL_{Xfmr} \times kV_{Applied}^{\ 2}}{kV_{Nameplate}^{\ 2}} \ \textbf{(kW)} \qquad \textbf{Eq. 4}$$

Where

NLL = No-load loss for the transformer

$NLL_{\ Xfmr}$ = No-load loss of transformer from certified test reports

$kV_{Applied}$ = Average voltage applied to transformer

$kV_{Nameplate}$ = Rated voltage of transformer

Load losses for each unit are obtained when possible due to wide-ranging characteristics between transformers of the same size and voltage class. Load losses at system peak can be calculated as follows:

$$LL_{\ Pk} = \frac{LL_{Xfmr} \times kVA_{Pk}^{\ 2}}{kVA_{Nameplate}^{\ 2}} \ \textbf{(kW)} \qquad \textbf{Eq. 5}$$

Where

$LL_{\ Pk}$ = Peak load loss of transformer at system coincident peak

$LL_{\ Xfmr}$ = Load loss of transformer from certified test reports

kVA_{Pk} = Load of transformer at system coincident peak

$kVA_{Nameplate}$ = Base rating of transformer

Total peak losses are calculated by adding no-load losses and load losses for the coincident transformer load at the system peak using Eq. 4 and Eq. 5.

$$LS_{Pk} = \sum_{n=1}^{N} \left(LL_{Pk_n} + NLL_n \right) \text{ (kW)} \qquad \textbf{Eq. 6}$$

Where

LL_{Pk}= Peak load loss of transformer at system coincident peak (see Eq. 5)

NLL = No-load loss for the transformer (see Eq. 4)

LS_{Pk}= Total peak losses for transformer at system coincident peak

n = Each transformer

Total energy losses can be calculated using hourly load data, as shown in Eq.7, or using peak losses multiplied by the loss factor, as shown in Eq.8, and adding no-load losses.

$$LS_{Energy} = \sum_{n=1}^{N} \sum_{h=1}^{T} LL_{HrLd}(h)_n + NLL_n \times T \text{ (kWh)} \qquad \textbf{Eq. 7}$$

Where

LS_{Energy} = Total energy losses for transformers

LL_{HrLd} = Load losses for each hour of the transformer load

h = Each hour

n = Each transformer

T = Hours of study period, 8,760 hours for annual analysis

or

$$LS_{Energy} = \sum_{n=1}^{N} \left(LL_{Pk_n} \times LSF_{Xfmr_n} + NLL_n \right) \times T \text{ (kWh)} \qquad \textbf{Eq. 8}$$

Where

LS_{Energy} = Total energy losses for transformers

LL_{Pk}= Peak load loss of transformer at system non-coincident peak

LSF = Loss factor for each transformer (see Eq. 2 and Eq. 3)

NLL = No-load loss for each transformer (see Eq. 4)

T = Hours of study period, 8,760 hours for annual analysis

n = Each transformer

Primary Lines

Computer simulations can be performed on circuits at the feeders' load at the system peak load (coincident load) and at the feeder peak load (non-coincident load). Losses at system peak are calculated by performing power-flow analysis for each feeder for the feeder load at the system peak (coincident loading). Energy losses can be calculated by determining losses for the feeder load at each hour or by using the feeder non-coincident peak load multiplied by the loss factor of the feeder.

For underground systems, the dielectric losses can be included. Power-flow computer simulations typically only include I^2R losses. Therefore, the dielectric losses are important to be added to the results and be accounted for also.

$$LS_{Pk} = \sum_{n=1}^{N} LnLS_n + LS_{UGC_n} \text{ (kW)} \qquad \textbf{Eq. 9}$$

Where

LS_{Pk} = Losses for a feeder at the feeder load during system peak (coincident load)

$LnLS(n)$ = Line losses (I^2R losses) for segment n from power-flow analysis

LS_{UGC} = Underground cable dielectric losses (specific for each cable size and type)

n = Each feeder

Another method for calculating dielectric losses includes determining the per-unit cable loss with the following equation:

Per foot cable loss = $0.00276(Eo^2)(\varepsilon)(\tan\delta)/(\mathrm{Log}\ (D/d))$ (**Watt/Ft/Cond**) **Eq. 10**

Where

Eo = Line to neutral voltage

ε = Dielectric constant of the insulating material

$\tan\delta$ = Dissipation factor

D = Outer diameter over insulation

d = Outer diameter of conductor

The annual energy dielectric losses for the defined per-unit cable loss described above includes multiplying the per-unit cable loss with the length of cable and hours in a year (8760).

Corona losses are also calculated for long overhead high-voltage transmission lines, typically above 345 kV. Corona is formed when the intensity of the electric field exceeds the breakdown strength of air, and ionization of the air occurs. It gives the effect of radio interference, which produces that buzzing/static sound that is heard near transmission lines. The method of calculation includes transmission line parameters such as radius, number of conductors in a bundle, bundle centers, configuration, phase spacing, voltage, line altitude, weather conditions, and some defined constants.

The energy losses for the primary lines can be calculated by running a power-flow analysis using hourly load data or at the feeder peak and multiplying by the loss factor for the feeder and then summing each feeder to get total primary line losses.

$$LS_{Energy} = \sum_{n=1}^{N} \sum_{h=1}^{T} LnLS_{HrLd}(h)_n + LS_{UGC_n} \times T \quad \textbf{(kWh)} \qquad \textbf{Eq. 11}$$

Where

LS_{Energy} = Energy losses for feeders

$LnLS_{HrLd}$ = Line losses for each hour of the feeder load

LS_{UGC} = Underground cable dielectric losses (specific for each cable size and type)

h = Each hour

n = Number of feeders

T = Hours of study period, 8,760 hours for annual analysis

or

$$LS_{Energy} = \left(\sum_{n=1}^{N} LnLS_{Peak_n} \times LSF_n + LS_{UGC_n} \right) \times T \quad \textbf{(kWh)} \qquad \textbf{Eq. 12}$$

Where

LS_{Energy} = Energy losses for feeders

$LnLS_{Peak}$ = Line losses at feeder non-coincident peak

LS_{UGC} = Underground cable dielectric losses (specific for each cable size and type)

n = Number of feeders

T = Number of hours, 8,670 hours for annual analysis

An alternative method for calculating primary line losses is by analyzing representative circuits and determining the percent losses (peak and energy) for each circuit type. Losses can then be calculated for each circuit by multiplying the appropriate percent peak and energy losses by the total peak and energy for that circuit. These circuits need to be chosen to include different voltage levels and customer type (primarily residential customers, commercial customers, industrial feeders, overhead, underground, and a combination of different service types including urban and rural).

Load placement can also be considered. If a feeder is chosen with a bulk of its distributed load near the front, it will illustrate different loss characteristics than one that has a fairly evenly distributed load or a heavy load at the end, such as a primarily residential feeder that supplies a strip mall at the end.

Line Equipment

Line equipment includes voltage regulators and surge arrestors for a distribution system. Losses for voltage regulators are calculated the same as for substation transformers (see Eq. 4 through Eq. 8).

The losses for a metal-oxide varistor (MOV) surge arrestor can be calculated for each voltage class. Typical leakage current is less than 1 mA and ranges from 0.5 mA to 0.7 mA. The losses are constant regardless of loading.

$$Losses = \sum_{n=1}^{n} kV_{\ln_n} \times 0.0006 \times Qty_n \times T \quad \textbf{(kWh)} \qquad \textbf{Eq. 13}$$

Where

n = Each voltage class

k$V\ ln$ = Kilovolts line to neutral

0.0006 = Leakage current of MOV arrestors

Qty = Quantity of arrestors

T = Duration of study period, 8,760 hours for annual analysis

Distribution Transformers

Many utilities have a transformer load management (TLM) system that includes inventories that can be used to develop a list of transformer sizes and ages. Nameplate loss data typically is not retained for individual distribution transformer unless it was entered into the TLM. Loss data can be obtained on transformers of similar age for each size from manufacturers, from various published documents, or from test reports that have been retained by the utility. Transformers can be grouped by age and/or type if the utility has changed practices over time, such as switching to more efficient transformers or adding loss requirements in the purchasing of transformers.

A significant challenge in calculating losses for distribution transformers is determining the system coincident peak load on the transformer. Three methods for determining loading can be used.

1. **A Detailed Computer Model.** A computer simulation model can assist in providing estimates, depending on how much detail was used in the development of the computer model. A detailed computer model may have each individual transformer modeled with the corresponding billing information. The computer model would then provide the peak losses, including the distribution transformers, by allocating the feeder load coincident with system peak proportional to each customer's billing.

   Detailed load data could be supplied by advanced metering infrastructure (AMI), indicating each customer's load at the time of the system peak to provide additional load information that can be used in load allocation.

2. **Feeder-Level Analysis.** The system coincident peak transformer loading can be calculated by using the ratio of connected transformers to the coincident feeder peaks and applying the load ratio to the transformer loss data. The transformer groupings—by size, type, and age—would be summarized for each feeder in the utility.

3. **Data Sampling.** Sampling of transformer percent loading at system peak could be used in lieu of the detailed computer model and/or AMI data. Each type of transformer configuration or grouping should have sufficient sampling to provide meaningful results.

Peak load losses can be determined by grouping the transformer sizes with similar customer classes and customer quantities for each size studied. Average transformer loading at system peak could be determined by one of the methods outlined above and then applied to the distribution transformer loss model. Load losses at peak system load could then be approximated with the following equation:

$$LL_{Pk} = \frac{LL_{Xfmr} \times kVA_{Pk}{}^2}{kVA_{Nameplate}{}^2} \text{ (kW)} \qquad \textbf{Eq. 14}$$

Where

LL_{Pk} = Peak load loss of transformer at system coincident peak

LL_{Xfmr} = Average load loss for classification/grouping of distribution transformer

kVA_{Pk} = Coincident load of transformer at system peak

$kVA_{Nameplate}$ = Base rating of transformer

No-load losses can be calculated simply by multiplying the quantity of each type of transformer by the no-load losses, adjusted for the applied voltage. Eq. 15 is similar to Eq. 4, but rather than using specific loss data for each transformer, average values are used for each transformer classification or grouping.

$$NLL = \left(\frac{NLL_{Xfmr} \times kV_{Applied}{}^2}{kV_{Nameplate}{}^2} \right) \text{ (kW)} \qquad \textbf{Eq. 15}$$

Where

NLL = No-load losses for distribution transformer

NLL_{Xfmr} = Average no-load losses for classification/grouping of distribution transformer

$kV_{Applied}$ = Average voltage that is applied to the distribution transformer

$kV_{Nameplate}$ = Nameplate voltage rating of the distribution transformer

Total peak losses are calculated by adding no-load loss and load losses for the coincident transformer load at the system peak using Eq. 14 and Eq. 15.

$$LS_{Pk} = \sum_{n=1}^{N} \left(LL_{Pk_n} + NLL_n \right) \times N \text{ (kW)} \qquad \textbf{Eq. 16}$$

Where

LS_{Pk} = Total peak losses for transformer at system coincident peak

LL_{Pk} = Peak load loss of transformer at system coincident peak (see Eq. 14)

NLL = No-load loss for the transformer (see Eq. 15)

n = Each transformer or classification/grouping

N = Number of transformers for each classification/grouping (if calculating losses by individual transformers, N = 1)

Total energy losses can be calculated using hourly load data or using peak losses multiplied by the loss factor and adding no-load loss then multiplying by time. The loss factor can be determined using Eq. 2 or Eq. 3, where the peak load is the non-coincident load or annual peak of the transformer.

$$LS_{Energy} = \sum_{n=1}^{N} \left(\sum_{h=1}^{T} LL_{HrLd}(h)_n + NLL_n \times T \right) \times N \text{ (kWh)} \qquad \textbf{Eq. 17}$$

Where

LS_{Energy} = Total energy losses for transformers

LL_{HrLd} = Load losses for each hour of the transformer load

h = Each hour

n = Each transformer or transformer classification/grouping

T = Hours of study period, 8,760 hours for annual analysis

N = Number of transformers for each classification/grouping (if calculating losses by individual transformers, N = 1)

or

$$LS_{Energy} = \sum_{n=1}^{N} \left(LL_{Pk_n} \times LSF_{Xfmr_n} + NLL_n \right) \times T \times N \text{ (kWh)} \qquad \textbf{Eq. 18}$$

Where

LS_{Energy} = Total energy losses for transformers

LL_{Pk} = Peak load loss of transformer at system non-coincident peak

LSF = Loss factor for each transformer (see Eq. 2 and Eq. 3)

T = Hours of study period, 8,760 hours for annual analysis

n = Each transformer or transformer classification/grouping

N = Number transformer for each classification/grouping (if calculating losses by individual transformers, N = 1)

Secondary and Services

For the purpose of the loss calculations, the secondary system is considered to be the portion of low-voltage conductor that serves more than one customer, and the service system is defined as the low-voltage conductors that serve only one customer. Ideally, secondary and service losses are calculated using a power-flow computer model in conjunction with the calculation of primary line and transformer losses. However, because most utilities do not have secondary and service systems modeled, the methodology for calculating these losses will likely include the use of sampling, design criteria, and load research data.

The exact methodology will depend on the data that is available for a particular utility. In general, secondary systems can be grouped together based on similar categories related to calculating losses. These categories may include conductor size, age of installation, customer class, overhead, underground, and voltage levels. Historical records or sampling of secondary systems can be used to determine the electrical characteristics, including conductor sizes (resistance), loads (magnitude, load factors, and imbalance), loss factors, coincidence factors, and diversity factors. Losses then could be approximated with the following equations:

$$LS_{Pk} = \sum_{n=1}^{N} \left(\frac{kW_{\mathrm{Pk}_{\mathrm{n}}} \times Cf}{V_{\mathrm{n}} \times 1000} \right)^2 \times imbF \times Lavg_{\mathrm{n}} \times R \times DF_{\mathrm{n}} \times N \text{ (kW)} \quad \textbf{Eq. 19}$$

$$LS_{Energy} = \sum_{n=1}^{N} \left(\frac{kW_{\mathrm{Pk}_{\mathrm{n}}}}{V_{\mathrm{n}} \times 1000} \right)^2 \times imbF \times LsF \times Lavg_{\mathrm{n}} \times R \times DF_{\mathrm{n}} \times T \times N \text{ (kWh)} \quad \textbf{Eq. 20}$$

Where

n = Grouping category

kW_{Pk} = Average peak demand

Cf = Coincident factor to convert average peak demand to demand during system peak

V = Voltage level line to line in volts; for three phase, V(n) = V(n)LL*1.7321

imbF = Imbalance factor for phase imbalance (balanced secondary imbF = 1, value increases as the phase imbalance increases)

LsF = Loss factor (see Eq. 2 and Eq. 3)

Lavg = Average conductor length in feet

R = Resistance of conductor per foot

DF = Diversity factor or coincidence factor (depends on the number of customers served) by the conductor

Number of Customers	***DF***
1	1.00
2	0.90
3	0.83
4	0.78
5	0.75
>10	0.70

N = Quantity of systems matching the grouping category

T = Hours of study period, 8,760 hours for annual analysis

Meters and Other Equipment

Equipment losses that occur on the utility's side of the meter can be included in the distribution losses. This equipment can be itemized separately for substation and distribution systems and includes equipment such as potential transformers, communication equipment, relays, surge arrestors, shunt reactors, rectifiers, meters, line regulators, network protectors, and capacitor equipment. Losses for each equipment type can be found on nameplate data or can be obtained from manufacturers. Station service, the electricity required to operate the distribution substation, may or may not be included as part of system losses, depending on the rules that the utility is following.

Revenue meters have two types of losses that are accounted for: First, the losses due to inaccuracy and second, the internal losses required for operations. Revenue metering inaccuracy is variable—it depends on the average percentage registration of the meter and on the energy throughput. The internal losses are fixed losses and vary depending on the type of meter (electromechanical or electronic).

The losses for most types of equipment are considered fixed, and therefore the calculations are straightforward. The losses for energy are the equipment losses multiplied by time.

$$Losses = \sum_{n=1}^{N} EquipmentLosses_n \times T \quad \textbf{(kWh)} \qquad \textbf{Eq. 21}$$

Where

n = Each type of equipment

T = Duration of study period, 8,760 hours for annual analysis

Unmetered Loads

Unmetered load typically includes streetlights, traffic lights, security lights, and theft. The energy used by the equipment and or stolen may be considered as load. Losses due to dedicated conductors and transformers to serve unmetered loads may also be considered as load.

Tariffs and regulations can be reviewed because they may provide information regarding the inclusion of unmetered load in rates, in which case these loads would not be included as losses. If metering of incoming and outgoing energy is used to reconcile loss calculations, then unmetered loads need to be accounted for as load in the reconciliation calculations.

Streetlights

Utilities range widely in the way that streetlight energy consumption and losses are funded. For example, some utilities have an agreement with another agency or with private owners to pay for the energy consumption and losses for streetlights, while other utilities provide street lighting.

Each utility needs to determine if streetlight consumption and losses are to be included as losses. Generally these loads can be included as fixed energy loads during the lighting hours. Street lighting loads would only be included in the peak loss calculations if the system peak occurred after dark when the streetlights would be energized.

One method for computing street lighting energy consumption is to use the number of street lights, the size of the street lights in watts (assume all the same size or use a few variations), and the hours in the day they are energized:

# of lights x hours of operation per day x wattage/1000 = kwh street lighting use

This determination of street lighting energy use can help in better estimating the "unaccounted for" losses. In addition, some utilities add a ballast loss factor on top of the street lighting use to account for ballast losses. The factors typically vary for each size and type of street light.

Theft

Each utility can determine what percent of total system load is associated with non-technical loads attributed to theft. This is typically estimated based on the difference between total system losses and quantifiable technical losses that have been identified.

C
DISTRIBUTION LOSS STUDY EXAMPLE

This distribution loss study example is presented by way of a calculation tool developed by EPRI and SAIC, which uses the equations explained in Appendix B that also came from the EPRI *Distribution Efficiency Initiative Study*. It identifies current industry practices, develops a methodology for best practices in determining system losses, and provides guidelines for utilities to use in accounting for system efficiencies for reducing system losses by implementing the calculation methods therein.

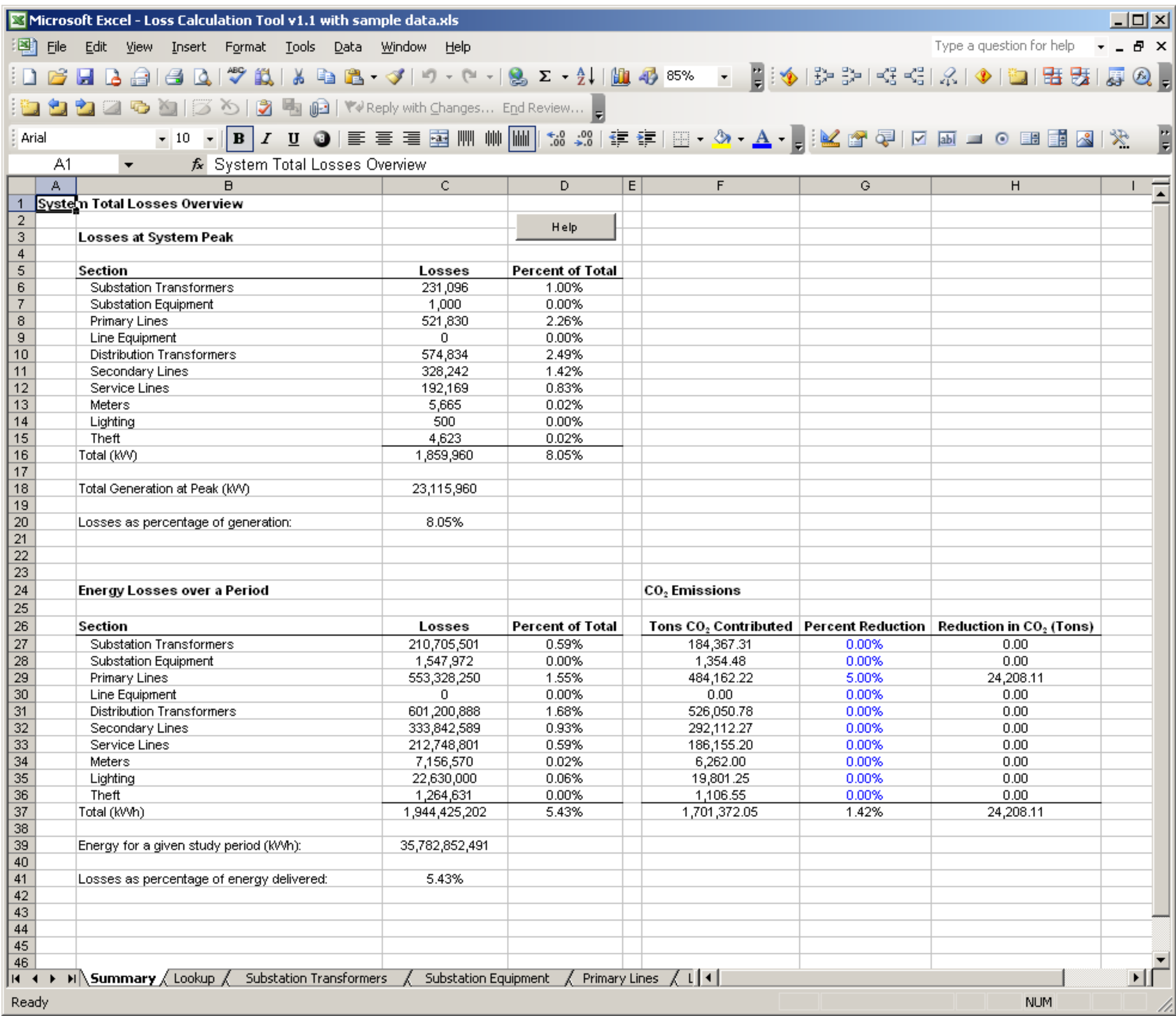
The tool was developed to support utilities in performing loss study calculations. It itemizes calculations to help engineers identify the equipment classes that are the largest contributors to the overall losses.

Although the sample data included in this example is representative of data provided by a utility, many assumptions were made to complete the loss calculations, even with missing or incomplete data. The bulk of the user's effort will be in data collection and performing intermediate calculations as needed to align their data with the necessary fields in the tool, especially data for secondary and service lines.

Example Calculation

Sample data is pre-loaded in the tool in order to develop an example of its use. The sample data in the tool is for illustration purposes only and was developed based upon the data that was provided to the developer. The user of the tool should verify any data that is being used. Limitations of the available sample data required that some assumptions be made. They will be listed here, by section.

A summary worksheet holds the collective results of the individual worksheets and calculates the totals for system peak losses and system energy losses.



Microsoft Excel - Loss Calculation Tool v1.1 with sample data.xls

System Total Losses Overview

Losses at System Peak

Section	Losses	Percent of Total
Substation Transformers	231,096	1.00%
Substation Equipment	1,000	0.00%
Primary Lines	521,830	2.26%
Line Equipment	0	0.00%
Distribution Transformers	574,834	2.49%
Secondary Lines	328,242	1.42%
Service Lines	192,169	0.83%
Meters	5,665	0.02%
Lighting	500	0.00%
Theft	4,623	0.02%
Total (kW)	1,859,960	8.05%

Total Generation at Peak (kW): 23,115,960

Losses as percentage of generation: 8.05%

Energy Losses over a Period / **CO_2 Emissions**

Section	Losses	Percent of Total	Tons CO_2 Contributed	Percent Reduction	Reduction in CO_2 (Tons)
Substation Transformers	210,705,501	0.59%	184,367.31	0.00%	0.00
Substation Equipment	1,547,972	0.00%	1,354.48	0.00%	0.00
Primary Lines	553,328,250	1.55%	484,162.22	5.00%	24,208.11
Line Equipment	0	0.00%	0.00	0.00%	0.00
Distribution Transformers	601,200,888	1.68%	526,050.78	0.00%	0.00
Secondary Lines	333,842,589	0.93%	292,112.27	0.00%	0.00
Service Lines	212,748,801	0.59%	186,155.20	0.00%	0.00
Meters	7,156,570	0.02%	6,262.00	0.00%	0.00
Lighting	22,630,000	0.06%	19,801.25	0.00%	0.00
Theft	1,264,631	0.00%	1,106.55	0.00%	0.00
Total (kWh)	1,944,425,202	5.43%	1,701,372.05	1.42%	24,208.11

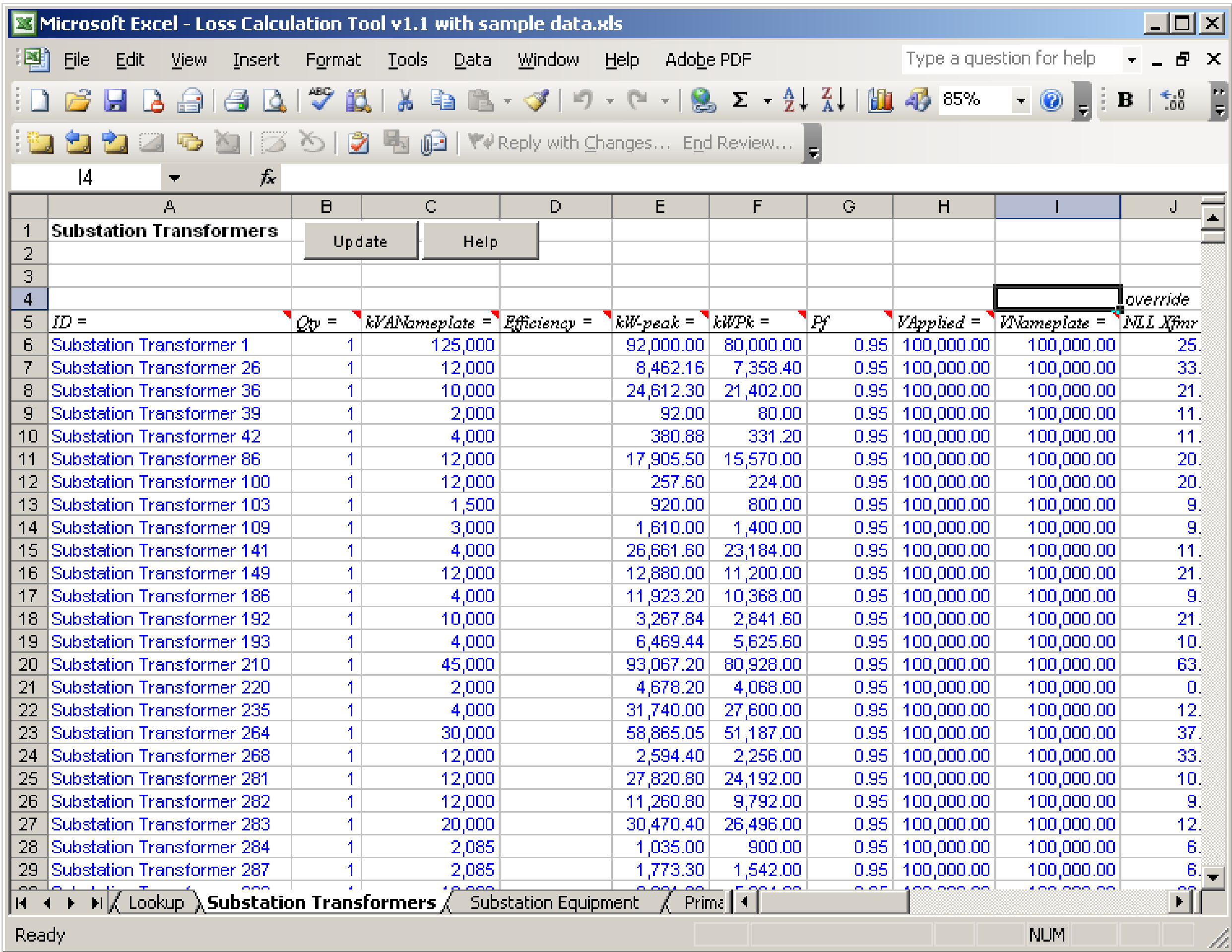
Energy for a given study period (kWh): 35,782,852,491

Losses as percentage of energy delivered: 5.43%

Figure 8-2: Summary Worksheet

Substation Transformers

From the sample data, each substation transformer is listed here, per the recommended usage. Because kWh information was not available, a fixed multiplier of 0.5 was used and multiplied by the duration times the coincident peak load. The voltage applied was assumed to be equal to the nameplate voltage of every transformer. The nameplate voltage was derived from the voltage class of the transformer. Finally, because individual peak load on each transformer was not known, a multiplier of 1.15 was used to translate from the coincident peak load data.



Microsoft Excel - Loss Calculation Tool v1.1 with sample data.xls

Substation Transformers

	A	B	C	D	E	F	G	H	I	J
1	Substation Transformers	Update	Help							
2										
3										
4										override
5	ID =	Qty =	kVANameplate =	Efficiency =	kW-peak =	kWPk =	Pf	VApplied =	VNameplate =	NLL Xfmr
6	Substation Transformer 1	1	125,000		92,000.00	80,000.00	0.95	100,000.00	100,000.00	25.
7	Substation Transformer 26	1	12,000		8,462.16	7,358.40	0.95	100,000.00	100,000.00	33.
8	Substation Transformer 36	1	10,000		24,612.30	21,402.00	0.95	100,000.00	100,000.00	21.
9	Substation Transformer 39	1	2,000		92.00	80.00	0.95	100,000.00	100,000.00	11.
10	Substation Transformer 42	1	4,000		380.88	331.20	0.95	100,000.00	100,000.00	11.
11	Substation Transformer 86	1	12,000		17,905.50	15,570.00	0.95	100,000.00	100,000.00	20.
12	Substation Transformer 100	1	12,000		257.60	224.00	0.95	100,000.00	100,000.00	20.
13	Substation Transformer 103	1	1,500		920.00	800.00	0.95	100,000.00	100,000.00	9.
14	Substation Transformer 109	1	3,000		1,610.00	1,400.00	0.95	100,000.00	100,000.00	9.
15	Substation Transformer 141	1	4,000		26,661.60	23,184.00	0.95	100,000.00	100,000.00	11.
16	Substation Transformer 149	1	12,000		12,880.00	11,200.00	0.95	100,000.00	100,000.00	21.
17	Substation Transformer 186	1	4,000		11,923.20	10,368.00	0.95	100,000.00	100,000.00	9.
18	Substation Transformer 192	1	10,000		3,267.84	2,841.60	0.95	100,000.00	100,000.00	21.
19	Substation Transformer 193	1	4,000		6,469.44	5,625.60	0.95	100,000.00	100,000.00	10.
20	Substation Transformer 210	1	45,000		93,067.20	80,928.00	0.95	100,000.00	100,000.00	63.
21	Substation Transformer 220	1	2,000		4,678.20	4,068.00	0.95	100,000.00	100,000.00	0.
22	Substation Transformer 235	1	4,000		31,740.00	27,600.00	0.95	100,000.00	100,000.00	12.
23	Substation Transformer 264	1	30,000		58,865.05	51,187.00	0.95	100,000.00	100,000.00	37.
24	Substation Transformer 268	1	12,000		2,594.40	2,256.00	0.95	100,000.00	100,000.00	33.
25	Substation Transformer 281	1	12,000		27,820.80	24,192.00	0.95	100,000.00	100,000.00	10.
26	Substation Transformer 282	1	12,000		11,260.80	9,792.00	0.95	100,000.00	100,000.00	9.
27	Substation Transformer 283	1	20,000		30,470.40	26,496.00	0.95	100,000.00	100,000.00	12.
28	Substation Transformer 284	1	2,085		1,035.00	900.00	0.95	100,000.00	100,000.00	6.
29	Substation Transformer 287	1	2,085		1,773.30	1,542.00	0.95	100,000.00	100,000.00	6.

Lookup / Substation Transformers / Substation Equipment / Prima

Ready NUM

Figure 8-3: Substation Transformers Worksheet

Substation Equipment

No data regarding substation equipment was provided, so an assumption was made in order to demonstrate this worksheet. Station service was added, with assumed parameters for each field.

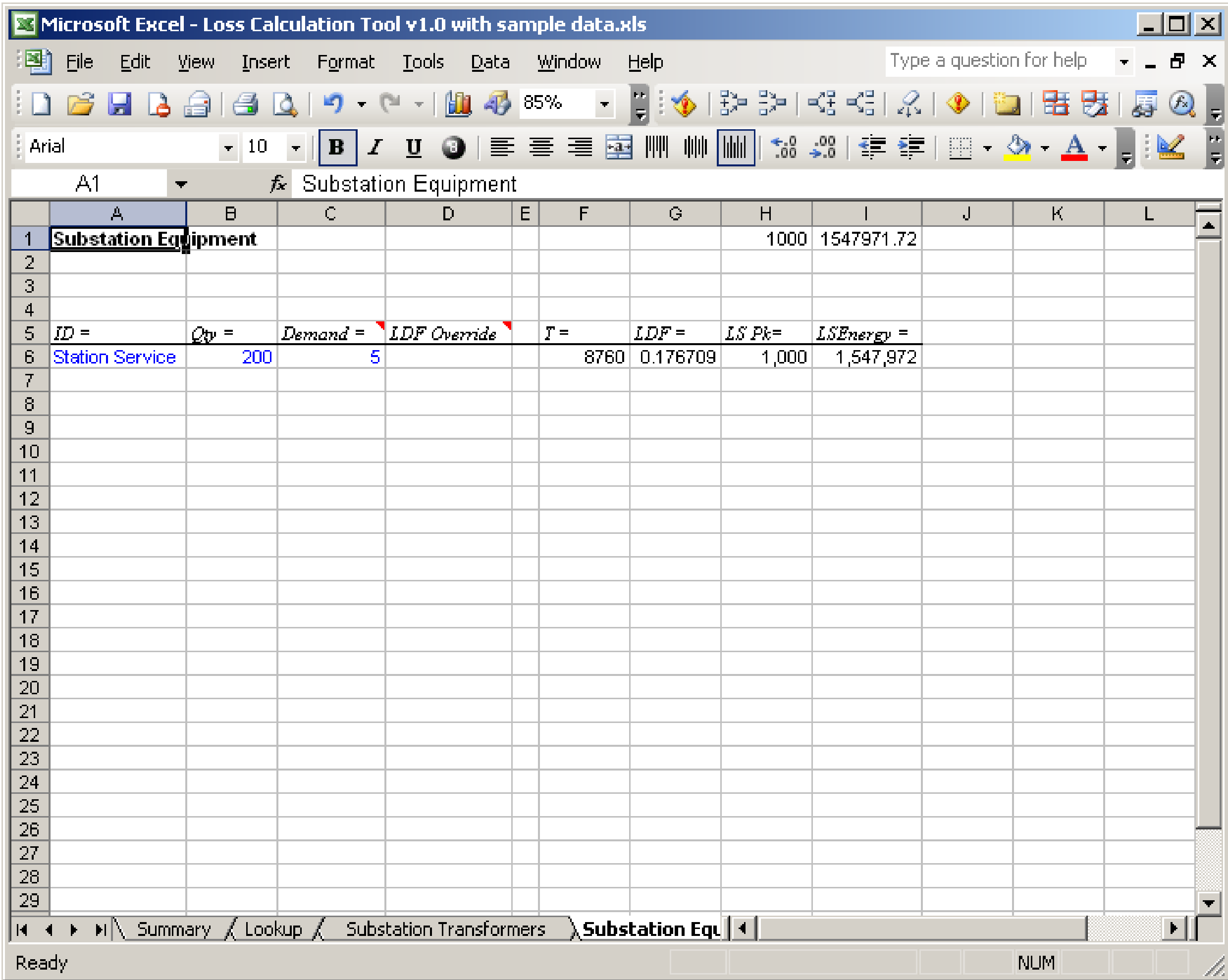
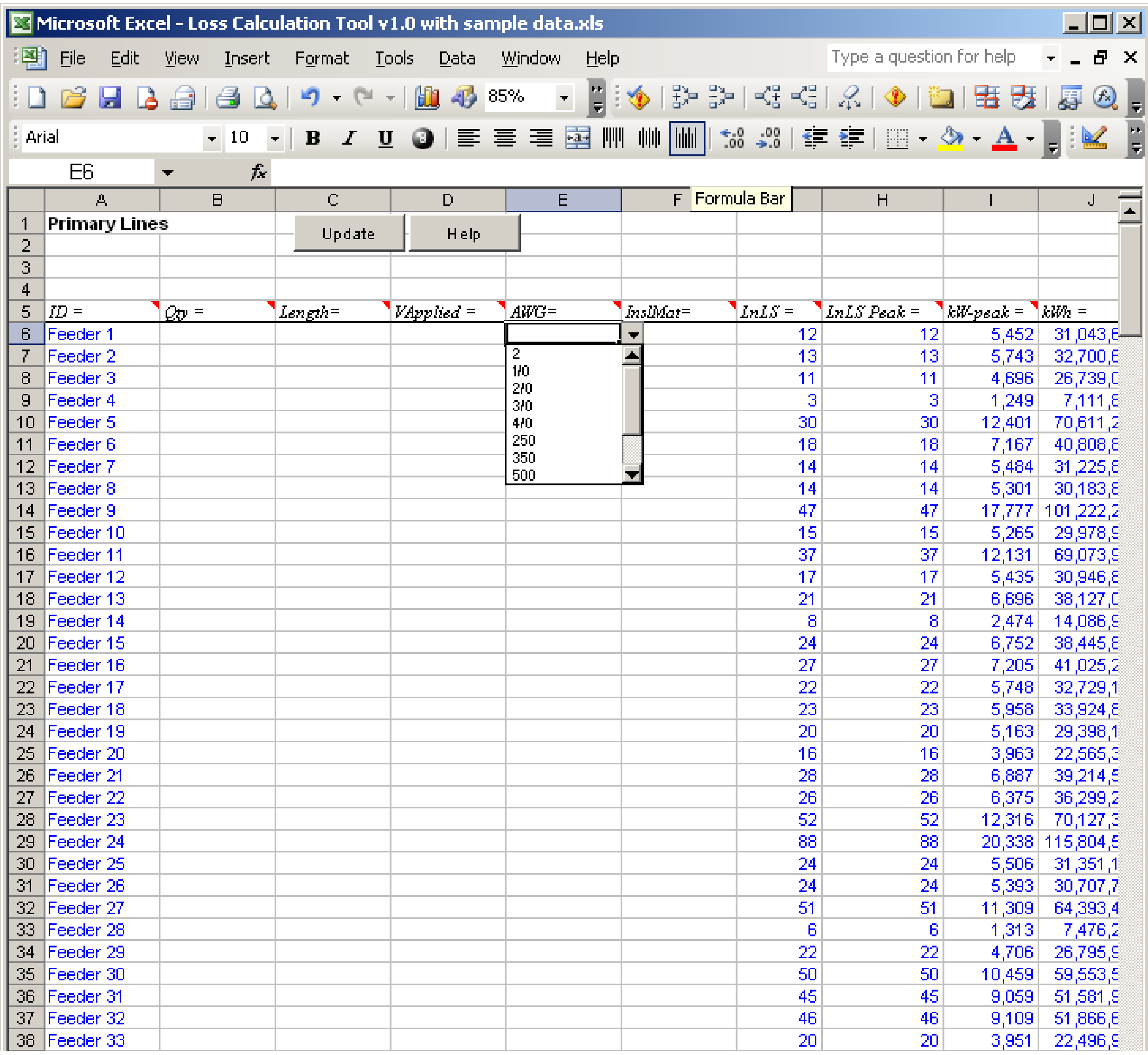


Figure 8-4: Substation Equipment Worksheet

Primary Lines

Loss data for 12 percent of the feeders was provided, which was entered into the tool. The field on the lookup sheet was updated to reflect the use of a sample. For simplicity, all lines were assumed to be overhead conductors. The kWh field was populated using a multiplier of 0.65 to translate the peak load to energy.

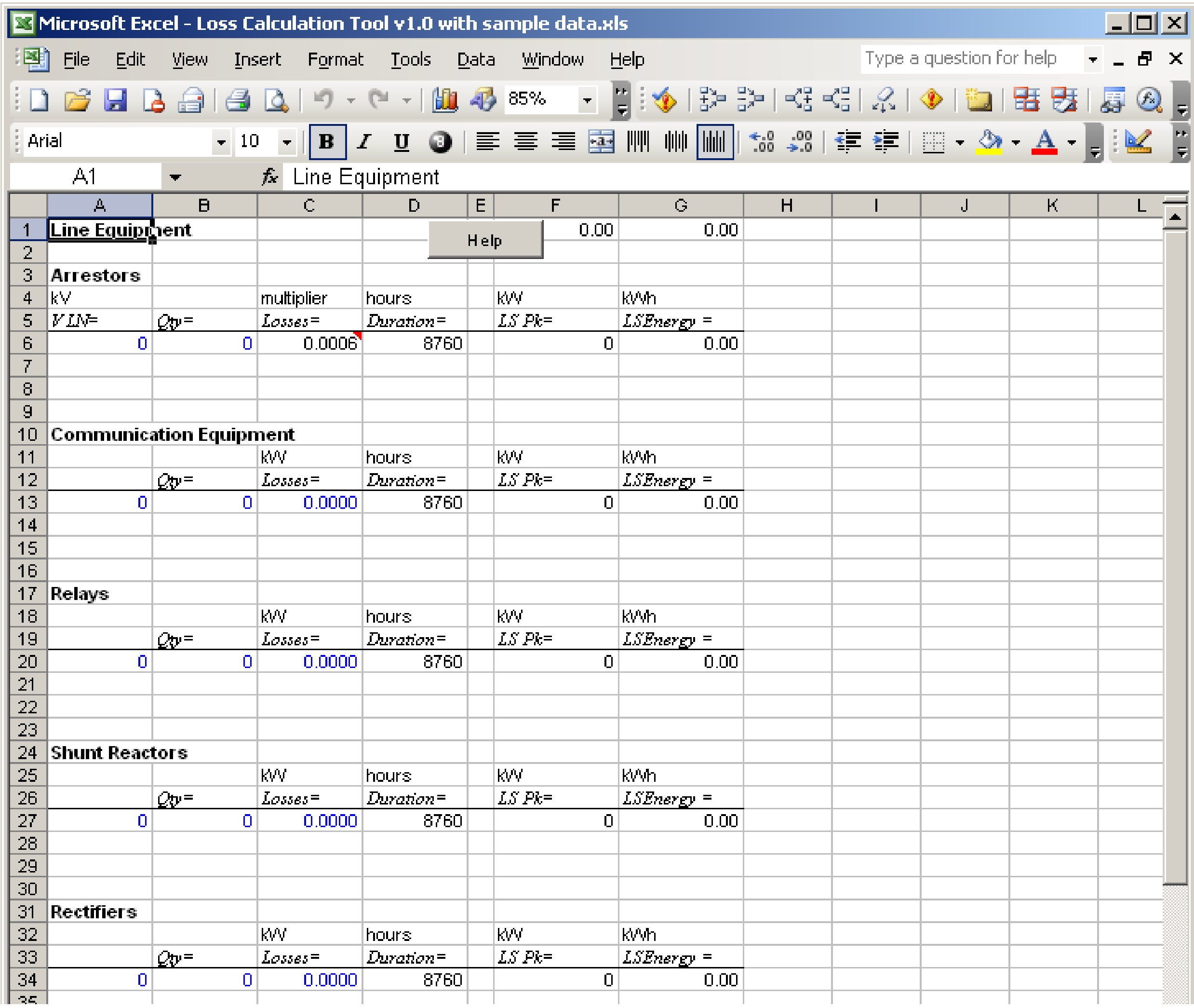


ID =	Qty =	Length=	VApplied =	AWG=	InslMat=	InLS =	InLS Peak =	kW-peak =	kWh =
Feeder 1						12	12	5,452	31,043,
Feeder 2						13	13	5,743	32,700,
Feeder 3						11	11	4,696	26,739,
Feeder 4						3	3	1,249	7,111,
Feeder 5						30	30	12,401	70,611,
Feeder 6						18	18	7,167	40,808,
Feeder 7						14	14	5,484	31,225,
Feeder 8						14	14	5,301	30,183,
Feeder 9						47	47	17,777	101,222,
Feeder 10						15	15	5,265	29,978,
Feeder 11						37	37	12,131	69,073,
Feeder 12						17	17	5,435	30,946,
Feeder 13						21	21	6,696	38,127,
Feeder 14						8	8	2,474	14,086,
Feeder 15						24	24	6,752	38,445,
Feeder 16						27	27	7,205	41,025,
Feeder 17						22	22	5,748	32,729,1
Feeder 18						23	23	5,958	33,924,
Feeder 19						20	20	5,163	29,398,1
Feeder 20						16	16	3,963	22,565,
Feeder 21						28	28	6,887	39,214,
Feeder 22						26	26	6,375	36,299,
Feeder 23						52	52	12,316	70,127,
Feeder 24						88	88	20,338	115,804,
Feeder 25						24	24	5,506	31,351,1
Feeder 26						24	24	5,393	30,707,7
Feeder 27						51	51	11,309	64,393,4
Feeder 28						6	6	1,313	7,476,
Feeder 29						22	22	4,706	26,795,
Feeder 30						50	50	10,459	59,553,
Feeder 31						45	45	9,059	51,581,
Feeder 32						46	46	9,109	51,866,
Feeder 33						20	20	3,951	22,496,

Figure 8-5: Primary Lines Worksheet

Line Equipment

No data regarding line equipment was provided. Because this is highly dependent on the equipment types that each utility uses, this worksheet was left as zeros.

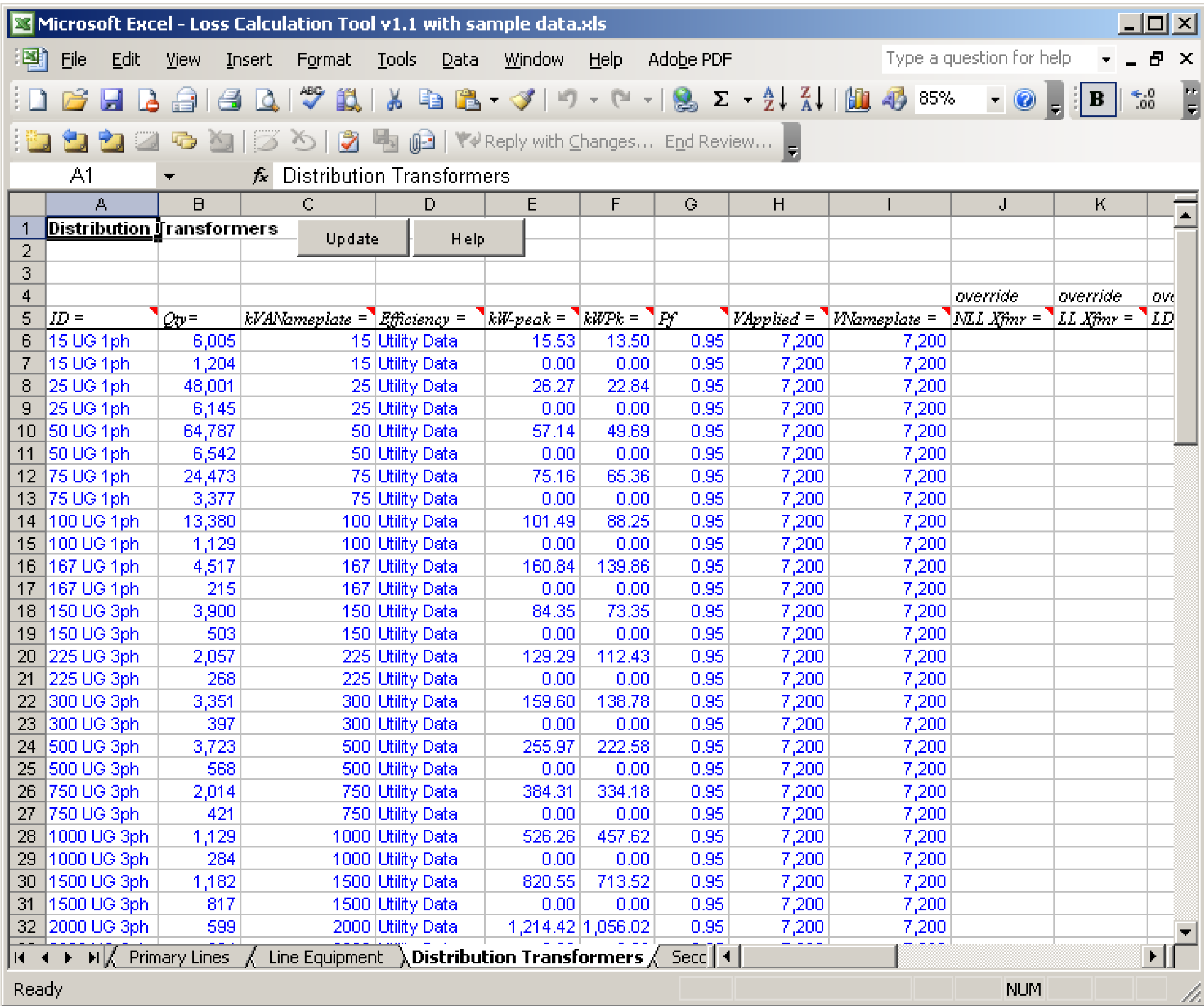


	A	B	C	D	E	F	G
1	**Line Equipment**					0.00	0.00
2							
3	**Arrestors**						
4	kV		multiplier	hours		kW	kWh
5	*V LN=*	*Qty=*	*Losses=*	*Duration=*		*LS Pk=*	*LSEnergy =*
6	0	0	0.0006	8760		0	0.00
7							
8							
9							
10	**Communication Equipment**						
11			kW	hours		kW	kWh
12		*Qty=*	*Losses=*	*Duration=*		*LS Pk=*	*LSEnergy =*
13	0	0	0.0000	8760		0	0.00
14							
15							
16							
17	**Relays**						
18			kW	hours		kW	kWh
19		*Qty=*	*Losses=*	*Duration=*		*LS Pk=*	*LSEnergy =*
20	0	0	0.0000	8760		0	0.00
21							
22							
23							
24	**Shunt Reactors**						
25			kW	hours		kW	kWh
26		*Qty=*	*Losses=*	*Duration=*		*LS Pk=*	*LSEnergy =*
27	0	0	0.0000	8760		0	0.00
28							
29							
30							
31	**Rectifiers**						
32			kW	hours		kW	kWh
33		*Qty=*	*Losses=*	*Duration=*		*LS Pk=*	*LSEnergy =*
34	0	0	0.0000	8760		0	0.00

Figure 8-6: Line Equipment Worksheet

Distribution Transformers

Distribution transformers are often a focal point of any distribution system loss study. The sample supplied to the developer included a list of sample transformers, along with their loading characteristics and their no-load and full-load losses. To utilize this data, the losses were averaged based on kVA size, entered into the tables on the lookup worksheet, and were then used in the calculations for determining total no-load and load losses. The non-coincident peak was estimated to be 15 percent higher than the coincident peak for every transformer. The applied voltage was assumed to be equal to the rated voltage in all cases. Finally, a load factor of 50 percent was used to calculate kWh from the coincident peak and the study duration. The sample data included transformers that were energized, but had no connected customers. Those were included in the study as well. Each transformer ID has a second worksheet row with a kWPk of zero, indicating no connected load. It is important to include these transformers, because their no-load losses are significant.

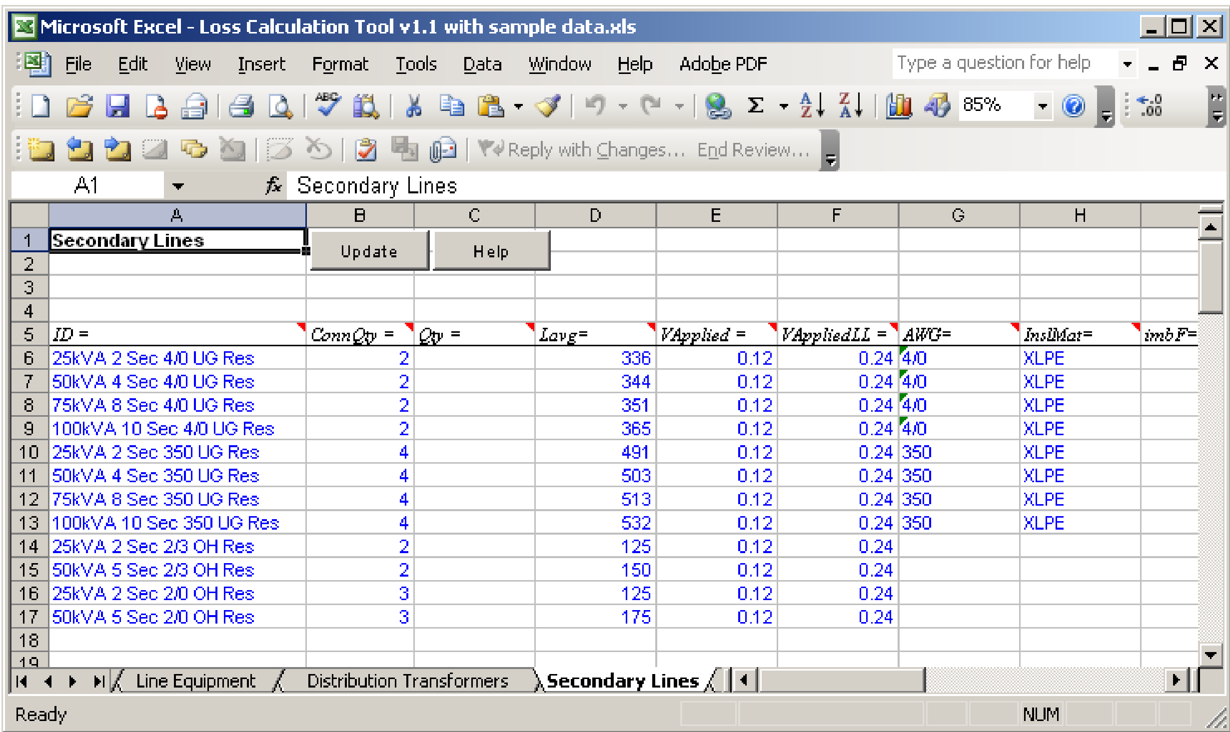


	ID =	Qty =	kVANameplate =	Efficiency =	kW-peak =	kWPk =	Pf	VApplied =	VNameplate =	override NLL Xfmr =	override LL Xfmr =
6	15 UG 1ph	6,005	15	Utility Data	15.53	13.50	0.95	7,200	7,200		
7	15 UG 1ph	1,204	15	Utility Data	0.00	0.00	0.95	7,200	7,200		
8	25 UG 1ph	48,001	25	Utility Data	26.27	22.84	0.95	7,200	7,200		
9	25 UG 1ph	6,145	25	Utility Data	0.00	0.00	0.95	7,200	7,200		
10	50 UG 1ph	64,787	50	Utility Data	57.14	49.69	0.95	7,200	7,200		
11	50 UG 1ph	6,542	50	Utility Data	0.00	0.00	0.95	7,200	7,200		
12	75 UG 1ph	24,473	75	Utility Data	75.16	65.36	0.95	7,200	7,200		
13	75 UG 1ph	3,377	75	Utility Data	0.00	0.00	0.95	7,200	7,200		
14	100 UG 1ph	13,380	100	Utility Data	101.49	88.25	0.95	7,200	7,200		
15	100 UG 1ph	1,129	100	Utility Data	0.00	0.00	0.95	7,200	7,200		
16	167 UG 1ph	4,517	167	Utility Data	160.84	139.86	0.95	7,200	7,200		
17	167 UG 1ph	215	167	Utility Data	0.00	0.00	0.95	7,200	7,200		
18	150 UG 3ph	3,900	150	Utility Data	84.35	73.35	0.95	7,200	7,200		
19	150 UG 3ph	503	150	Utility Data	0.00	0.00	0.95	7,200	7,200		
20	225 UG 3ph	2,057	225	Utility Data	129.29	112.43	0.95	7,200	7,200		
21	225 UG 3ph	268	225	Utility Data	0.00	0.00	0.95	7,200	7,200		
22	300 UG 3ph	3,351	300	Utility Data	159.60	138.78	0.95	7,200	7,200		
23	300 UG 3ph	397	300	Utility Data	0.00	0.00	0.95	7,200	7,200		
24	500 UG 3ph	3,723	500	Utility Data	255.97	222.58	0.95	7,200	7,200		
25	500 UG 3ph	568	500	Utility Data	0.00	0.00	0.95	7,200	7,200		
26	750 UG 3ph	2,014	750	Utility Data	384.31	334.18	0.95	7,200	7,200		
27	750 UG 3ph	421	750	Utility Data	0.00	0.00	0.95	7,200	7,200		
28	1000 UG 3ph	1,129	1000	Utility Data	526.26	457.62	0.95	7,200	7,200		
29	1000 UG 3ph	284	1000	Utility Data	0.00	0.00	0.95	7,200	7,200		
30	1500 UG 3ph	1,182	1500	Utility Data	820.55	713.52	0.95	7,200	7,200		
31	1500 UG 3ph	817	1500	Utility Data	0.00	0.00	0.95	7,200	7,200		
32	2000 UG 3ph	599	2000	Utility Data	1,214.42	1,056.02	0.95	7,200	7,200		

Figure 8-7: Distribution Transformers Worksheet

Secondary Lines

Quantities of secondary lines were not known, so a relative sample had to be used. The average length and resistance of a service conductor was included in the sample data. The number of connected customers per secondary was known, and the peak amperage and peak demand per customer were also known. The kW-peak was calculated by multiplying the number of connected customers per secondary by the peak demand per customer. This allowed the energy to be estimated using a load factor of 45.49 percent from the sample data. The power factor was assumed to be 85 percent. The line-to-line voltage applied is 240 volts and is based on the voltage data provided. The line loss non-coincident peak is assumed to be equal to the coincident peak line loss. A phase imbalance factor of 1.15 was used, and a coincident factor of 0.9 or 0.8 was also assumed based on reasonable estimates. Underground conductors were assumed to be XLPE insulated for calculating dielectric losses. The diversity factor is dependent on the number of customers served by the conductor.

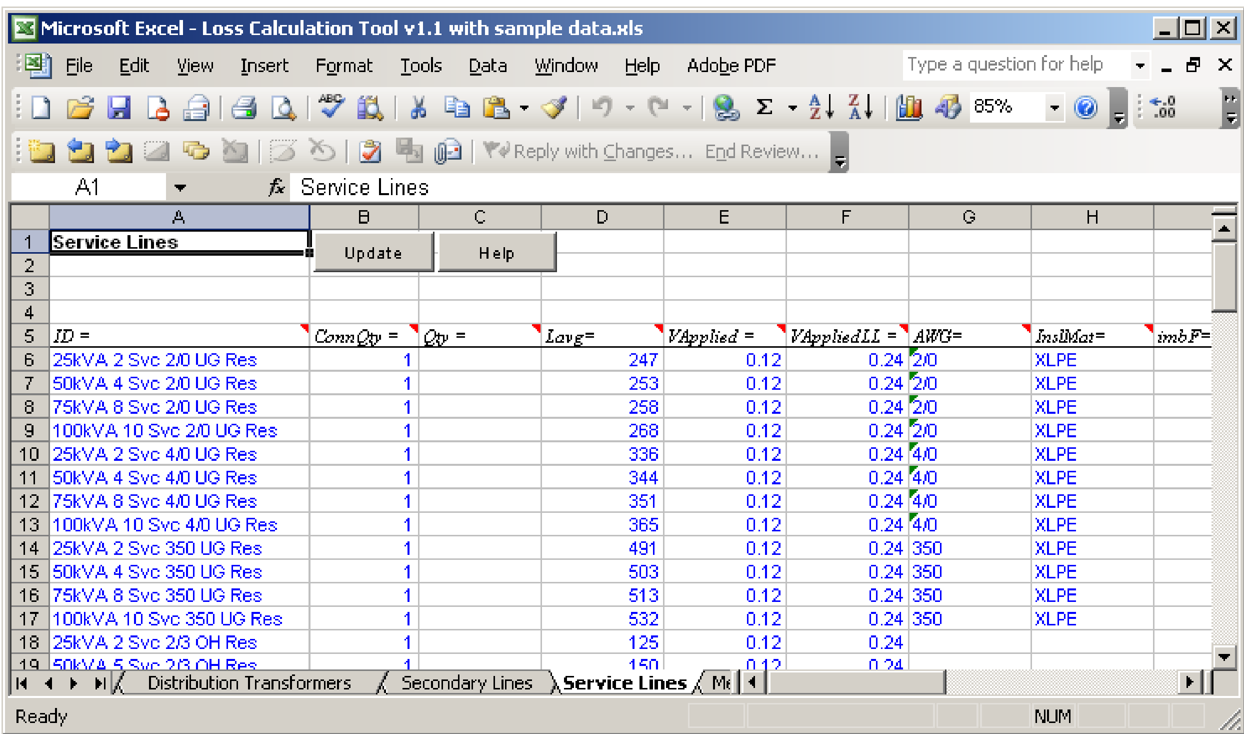


	A	B	C	D	E	F	G	H	
1	Secondary Lines								
2									
3									
4									
5	ID =	ConnQty =	Qty =	Lavg=	VApplied =	VAppliedLL =	AWG=	InslMat=	imbF=
6	25kVA 2 Sec 4/0 UG Res	2		336	0.12	0.24	4/0	XLPE	
7	50kVA 4 Sec 4/0 UG Res	2		344	0.12	0.24	4/0	XLPE	
8	75kVA 8 Sec 4/0 UG Res	2		351	0.12	0.24	4/0	XLPE	
9	100kVA 10 Sec 4/0 UG Res	2		365	0.12	0.24	4/0	XLPE	
10	25kVA 2 Sec 350 UG Res	4		491	0.12	0.24	350	XLPE	
11	50kVA 4 Sec 350 UG Res	4		503	0.12	0.24	350	XLPE	
12	75kVA 8 Sec 350 UG Res	4		513	0.12	0.24	350	XLPE	
13	100kVA 10 Sec 350 UG Res	4		532	0.12	0.24	350	XLPE	
14	25kVA 2 Sec 2/3 OH Res	2		125	0.12	0.24			
15	50kVA 5 Sec 2/3 OH Res	2		150	0.12	0.24			
16	25kVA 2 Sec 2/0 OH Res	3		125	0.12	0.24			
17	50kVA 5 Sec 2/0 OH Res	3		175	0.12	0.24			
18									
19									

Figure 8-8: Secondary Lines Worksheet

Service Lines

Because of the similarities between secondary and service conductors, this worksheet has similar assumptions to the secondary lines worksheet. The average length and resistance of a service conductor was included in the sample data. The number of connected customers per service line was known to be 1. Sample data provided the peak demand and peak amperage per customer. The line-to-line voltage applied is 240 volts at a power factor of 85 percent and is based on the voltage data provided. The line loss non-coincident peak is taken to be equal to the coincident peak line loss. A phase imbalance factor of 1.15 is assumed, and a coincident factor of 1 is also used based on reasonable estimates. Underground conductors were assumed to be XLPE insulated for calculating dielectric losses. The diversity factor is dependent on the number of customers served by the conductor.

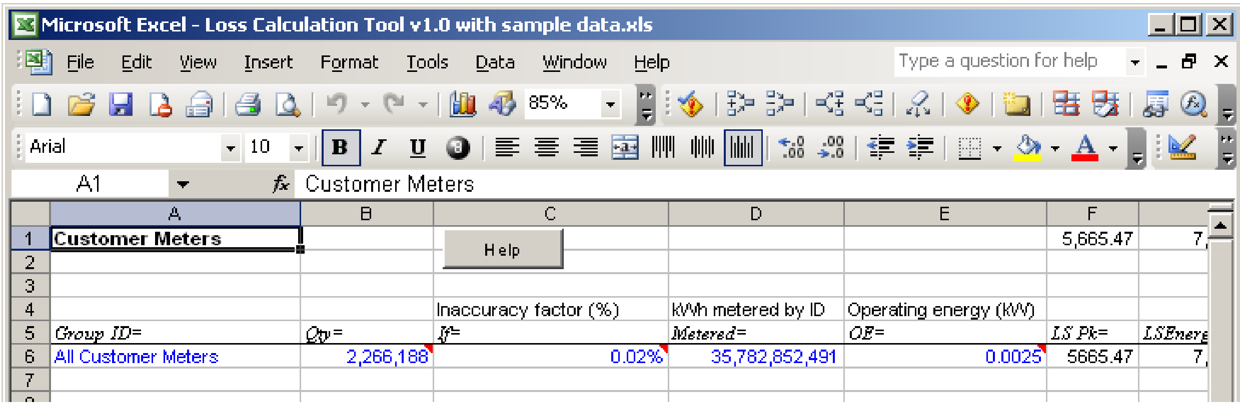


	A	B	C	D	E	F	G	H	
1	Service Lines								
5	*ID =*	*ConnQty =*	*Qty =*	*Lavg=*	*VApplied =*	*VAppliedLL =*	*AWG=*	*InslMat=*	*imbF=*
6	25kVA 2 Svc 2/0 UG Res	1		247	0.12	0.24	2/0	XLPE	
7	50kVA 4 Svc 2/0 UG Res	1		253	0.12	0.24	2/0	XLPE	
8	75kVA 8 Svc 2/0 UG Res	1		258	0.12	0.24	2/0	XLPE	
9	100kVA 10 Svc 2/0 UG Res	1		268	0.12	0.24	2/0	XLPE	
10	25kVA 2 Svc 4/0 UG Res	1		336	0.12	0.24	4/0	XLPE	
11	50kVA 4 Svc 4/0 UG Res	1		344	0.12	0.24	4/0	XLPE	
12	75kVA 8 Svc 4/0 UG Res	1		351	0.12	0.24	4/0	XLPE	
13	100kVA 10 Svc 4/0 UG Res	1		365	0.12	0.24	4/0	XLPE	
14	25kVA 2 Svc 350 UG Res	1		491	0.12	0.24	350	XLPE	
15	50kVA 4 Svc 350 UG Res	1		503	0.12	0.24	350	XLPE	
16	75kVA 8 Svc 350 UG Res	1		513	0.12	0.24	350	XLPE	
17	100kVA 10 Svc 350 UG Res	1		532	0.12	0.24	350	XLPE	
18	25kVA 2 Svc 2/3 OH Res	1		125	0.12	0.24			
19	50kVA 5 Svc 2/3 OH Res	1		150	0.12	0.24			

Figure 8-9: Service Lines Worksheet

Meters

For illustrative purposes, it was assumed that every distribution transformer had three meters connected to it. Reasonable assumptions about the inaccuracy factor and the operating energy were made.

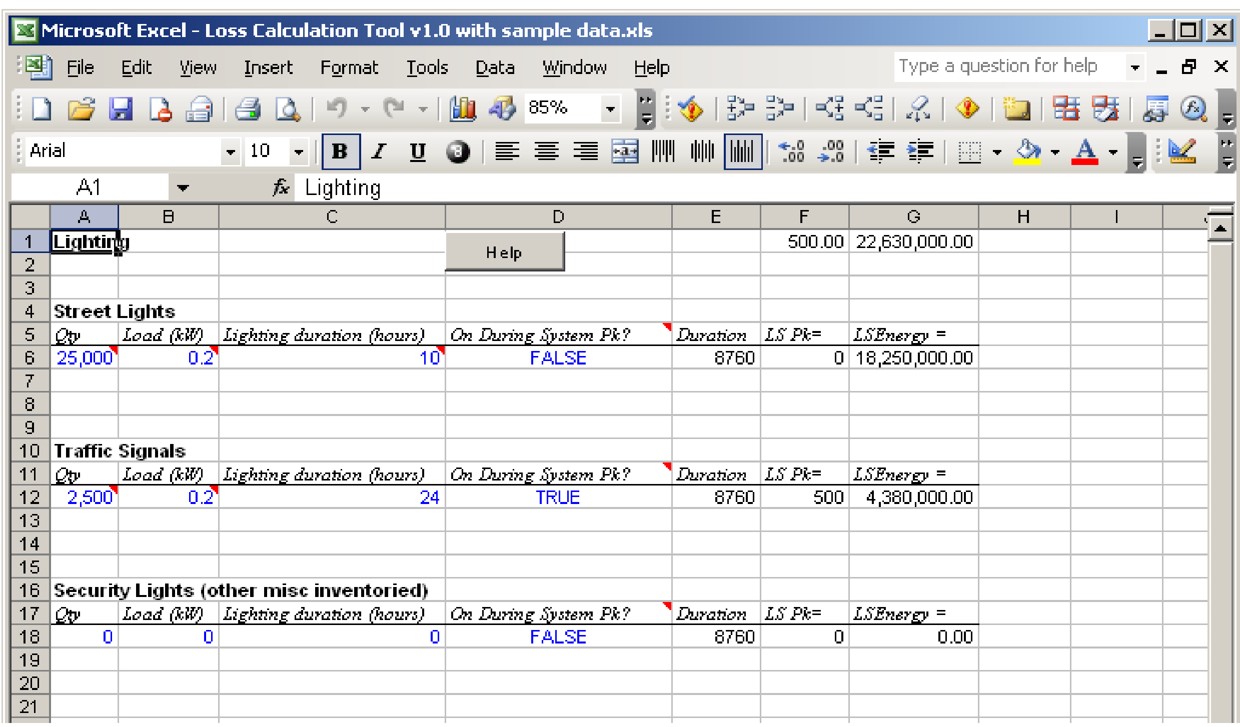


	A	B	C	D	E	F	G
1	Customer Meters		Help			5,665.47	7,
2							
3							
4			Inaccuracy factor (%)	kWh metered by ID	Operating energy (kW)		
5	*Group ID=*	*Qty=*	*If=*	*Metered=*	*OE=*	*LS Pk=*	*LSEnerg*
6	All Customer Meters	2,266,188	0.02%	35,782,852,491	0.0025	5665.47	7,
7							

Figure 8-10: Meters Worksheet

Lighting

No data was provided regarding street lighting or other types of unmetered illumination, so assumptions were made to illustrate the usage of this worksheet. All numbers shown are assumptions and are tagged as such with cell comments.



	A	B	C	D	E	F	G
1	Lighting			Help		500.00	22,630,000.00
2							
3							
4	Street Lights						
5	*Qty*	*Load (kW)*	*Lighting duration (hours)*	*On During System Pk?*	*Duration*	*LS Pk=*	*LSEnergy =*
6	25,000	0.2	10	FALSE	8760	0	18,250,000.00
7							
8							
9							
10	Traffic Signals						
11	*Qty*	*Load (kW)*	*Lighting duration (hours)*	*On During System Pk?*	*Duration*	*LS Pk=*	*LSEnergy =*
12	2,500	0.2	24	TRUE	8760	500	4,380,000.00
13							
14							
15							
16	Security Lights (other misc inventoried)						
17	*Qty*	*Load (kW)*	*Lighting duration (hours)*	*On During System Pk?*	*Duration*	*LS Pk=*	*LSEnergy =*
18	0	0	0	FALSE	8760	0	0.00
19							
20							
21							

Figure 8-11: Lighting Worksheet

Theft

No information regarding theft was provided. It was estimated that theft accounted for 0.02 percent of the total peak and energy to illustrate the use of this worksheet.

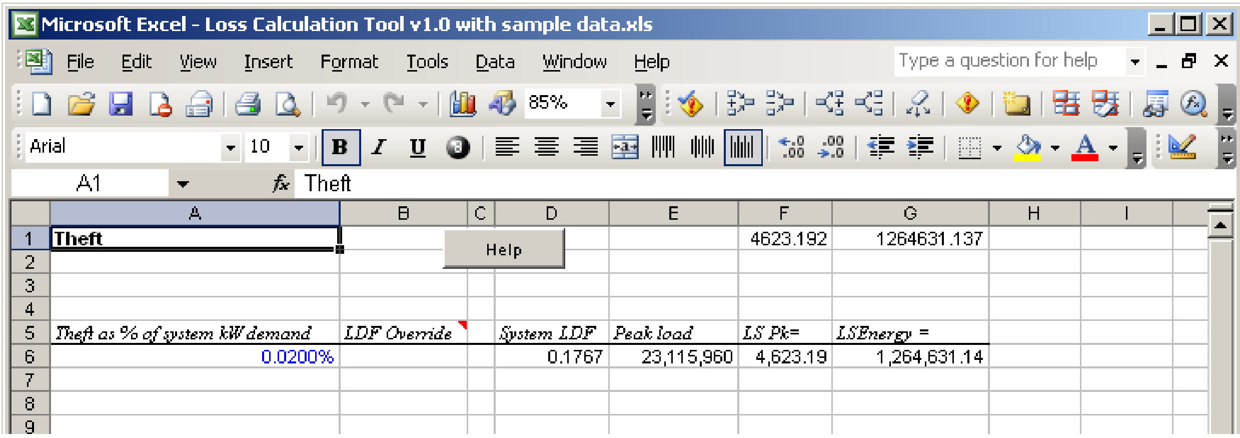


Figure 8-12: Theft Worksheet

D
DEMAND MANAGEMENT CASE STUDY

ICE Energy retained SAIC to develop a technical guide to modeling an ICE Bear System. The ICE Bear System is an energy-storage system designed to provide sufficient ice storage to displace the operation of a five-ton air-conditioning compressor operating at 100 percent duty cycle for approximately six hours (peak summer operation of the AC system). The ICE Bear System then needs approximately ten hours of off-peak operation of its compressor to recharge the ice storage to full capacity.

SAIC worked in collaboration with ICE Energy and Milsoft Integrated Solutions, Inc., to develop a programming script and methodology to model ICE Bear systems in Milsoft's WindMil™ software and study the effects of the ICE Bear technology on distribution systems. WindMil™ is engineering analysis software capable of performing distribution load-flow analysis, among a suite of various other analysis functions. Utilities can control the off-peak operation and dispatch the stored energy of the ICE Bears as a demand-management system.

The impacts from installing ICE Bear Systems can result in potential benefits to the electric system and include, but are not limited to, the following:

- Avoided or delayed generating or purchased power capacity additions.
- Avoided costs of electricity production (swap of high-cost, on-peak energy for lower-cost, off-peak energy).
- Improvements in distribution system power factor and voltage support.
- Avoided electric system losses.
- Avoided or delayed transmission system improvements.
- Avoided or delayed distribution system improvements.

The placement of the ICE Bear units in the distribution models was limited to consumers/transformers with allocated peak three-phase load between 20 kW and 350 kW to keep the focus on the commercial sector. Multiple units could be placed at a single location, which is a true representation. Various other assumptions regarding typical HVAC loading at peak and the number of units to be placed were decided upon for use in the study.

ICE Energy staff estimates each ICE Bear unit will reduce peak load by 6.7 kW for a non-desert environment and 8.0 kW for a desert environment, at the secondary voltage level. The analysis focused on non-desert environments. The associated power factor of the peak load reduction was estimated to be 70 percent.

The results showed loss reductions and improvements in voltage, capacity release, and power factor. By placing a limit of 200 ICE Bear units on each feeder, peak loss improvements ranged from 8 percent to 20 percent per feeder. A sensitivity analysis evaluated the entire distribution system of each participating client at various levels of saturation.

With saturation levels between 25 percent and 100 percent of available locations to locate an ICE Bear unit, improvements in peak load loss ranged between 5 percent and 43 percent. The total peak load reduction ranged between 2 percent and 23 percent.

Figure D-1 provides an example representation of the staggered operation of 200 megawatts of installed ICE Bear units, or approximately 30,000 ICE Bear units, on a typical summer day to produce a diversified impact on the electric system load shape across a 24 hour period. The chart depicts the installation of the ICE Bear units on 10 percent of the commercial electric customers of a 3,000 megawatt electric system and reflects an electric utility load pattern and ICE Bear System operation. By shifting load from peak to off-peak, system losses are reduced.

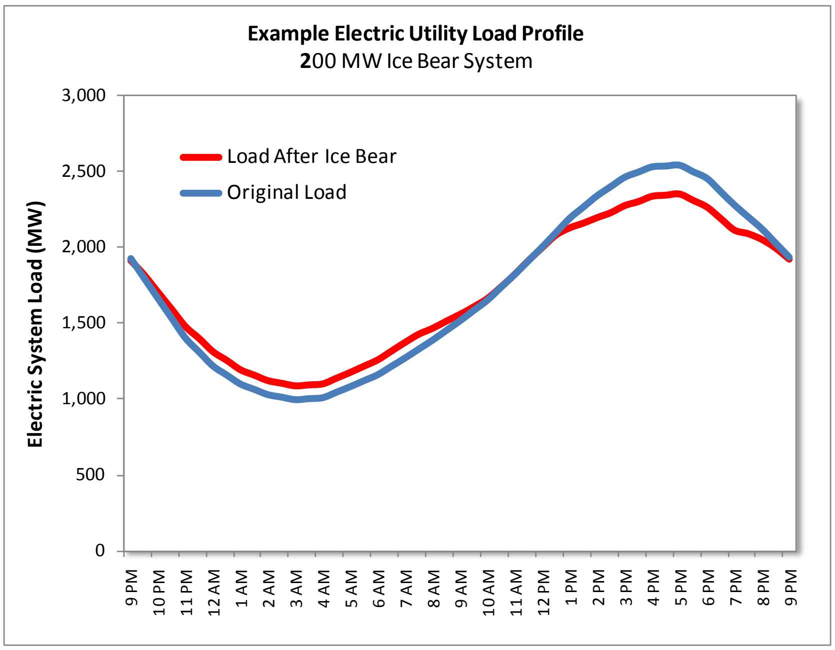


Figure G-1: Load Shift due to ICE Bear Cooling System

E
VOLTAGE OPTIMIZATION CASE STUDY

The Northwest Energy Efficiency Alliance's (NEEA) Distribution Efficiency Initiative (DEI) and the Northwest Power and Conservation Council's (NWPCC) Sixth Northwest Power Plan identified distribution system efficiency as an untapped, low-cost energy resource. As a result, regulatory bodies and electric utilities are beginning to incorporate efficiency measures into their overall integrated resource planning strategies.

Bonneville Power Administration (BPA) developed the Energy Smart Utility Efficiency (ESUE) Voltage Optimization (VO) program that incentivizes utilities to improve the efficiency of the distribution system and help public utilities meet regional goals established by the Northwest Power and Conservation Council's (NWPCC) Sixth Northwest Power Plan. The NWPCC energy efficiency goals included potential distribution efficiency savings based on the NEEA DEI research project completed by SAIC in 2007. The ESUE program was developed based on the pilot demonstration projects established from the NEEA DEI study and research performed by Dr. Robert Fletcher. It was vetted through a series of multiple workshops by the technical evaluation committee, which included engineers and energy efficiency staff from 20 utilities.

The ESUE program established a set of performance criteria for distribution systems and requires the utility to operate at a voltage level in the lower acceptable range. In addition, the technical committee created the simplified VO protocols that simplify the measurement and verification process. The incentives provided by BPA include the cost of performing Scoping and Detail planning studies and, if the utility implements the program, pay the utility $0.25 for each kWh saved in the first year or 70 percent of the project's installed costs required to tune the system, whichever is less. The $0.25/kWh saved is a blended rate over five years.

The ESUE program was designed to simplify the process for determining the savings for implementing system improvements and optimizing the voltage levels. The simplified VO protocol reduces the measurement and verification period from one year down to a few weeks by employing the research results from the NEEA study and performing system analysis on the feeders to determine voltage reduction and energy savings for the utility and for the end-use customer. The figure below outlines the process where the existing performance of the distribution system is established, system improvements are identified and implemented to tune the system, a week of measurements is taken to establish pre-VO performance verifying that the system is meeting the performance criteria, the voltage levels are reduced, and another week of measurements is recorded, verifying that the voltage levels are at the minimum levels. The project is then tracked for three years to determine whether the energy savings are being captured.

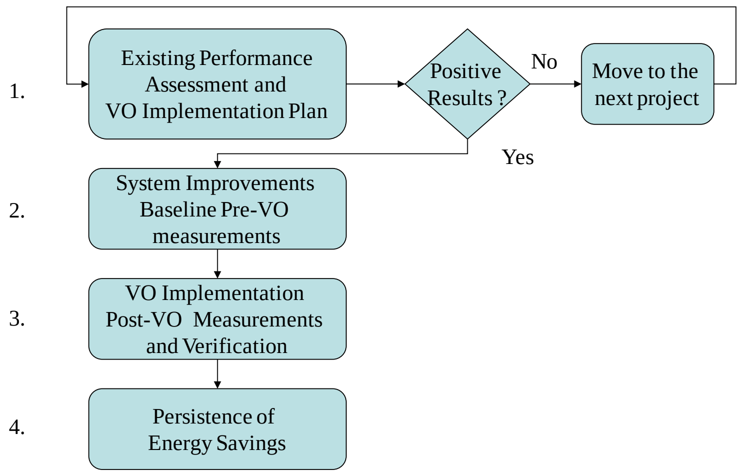


Figure 8-13: ESUE Program Process

The performance criteria thresholds were establish to reduce system losses, limit the total voltage drop on the primary feeders, and flatten the voltage profile of feeders. The thresholds include phase balancing, power factor, voltage drop, and voltage balance, which are listed below:

- Voltage drop (primary) < 3.3 percent
- Power factor > 98 percent on average, minimum > 96 percent
- Phase balancing > 0.15 pu, or < 40 amps on neutral
- Voltage drop variance (between feeders) < 0.25p.u. or < 2.0V 120Vbase

The basic formula used to calculate total energy savings for ESUE projects is listed below:

$$E\ Saved = \Delta V \times VO_f \times E_{Annual} + \Delta E_{XFMR\_NL} + \Delta E_{LineLosses}$$

ΔV = Annual average voltage reduction, per unit

VO_f = End-use voltage optimization factor as calculated from the NEEA DEI study results (%ΔE/% ΔV)

E_{Annual} = Annual energy consumption of project

ΔE_{XFMR_NL} = Reduction in no-load losses of the distribution transformers (proportional to ΔV^2)

$\Delta E_{LineLosses}$ = Reduction in line losses due to due to system improvements

SAIC has performed ESUE studies for seven utilities that include 21 substations and 70 distribution feeders. A typical ESUE project consists of three substations and an average of 10 feeders. Power-flow models were used to determine existing system performance, required system improvements, reduction in electric losses from the improvements, and new operating voltage levels for the distribution system. Cost estimates were created for the system improvements, and operations and maintenance costs were included for additional capital investments.

The benefits were calculated based on the marginal cost of producing the next kWh as provided by each utility, ranging from $23 to $55 a MW, and the benefits were assumed to continue for 15 years. Benefit-to-cost ratios were developed for each utility and were not developed for each type of system improvement. The table below shows the results of the analysis where the benefit-to-cost ratios ranged from less than 1.0 (not cost effective) to greater than 10.

Several substations were the worst performing substations for the utilities and required significant improvements, including reconductoring and new feeders, to meet the ESUE performance requirements, resulting in an overall benefit-to-cost ratio of 1.10 for the seven utilities included in the study. The total investment was $9.3M or $487k per substation (19 substations) or $117k per feeder (79 feeders). Total energy savings were estimated at 1.3 percent and 19,837 MWh/yr, where 11.3 percent of the savings were from system losses and 88.7 percent from end-use customer load.

Table E-1
ESUE Cost/Benefit Calculations for All Systems Studied

	Annual Energy (MWH/yr)	Cost of System Improvements	Line Loss Saved (MWh/yr)	No-Load Loss Saved (MWhyr)	VO Energy Saved (MWh/yr)	Total Energy Savings for Project (MWh/yr)	% Reduction in Annual Energy - Utility	% Reduction in Annual Energy - Customer	% Reduction in Annual Energy - Total	BCR
Utility **A**	193,987	$1,302,149	505.4	80.4	1,013.3	1,599.2	0.302%	0.522%	0.824%	0.84
Utility **B**	218,852	$294,638	179.5	35.9	1,209.7	1,425.1	0.098%	0.553%	0.651%	2.97
Utility **C**	247,600	$150,000	14.4	92.1	2,880.0	2,986.5	0.043%	1.163%	1.206%	14.92
Utility **D**	170,830	$3,956,526	648.8	68.2	3,559.3	4,276.3	0.420%	2.084%	2.503%	0.74
Utility **E**	216,044	$172,800	5.6	29.3	3,430.1	3,464.9	0.016%	1.588%	1.604%	12.49
Utility **F**	167,907	$2,782,065	279.4	163.6	1,780.3	2,223.3	0.264%	1.060%	1.324%	0.34
Utility **G**	314,824	$443,662	115.9	18.5	3,728.0	3,862.3	0.043%	1.184%	1.227%	5.81
Totals	1,530,043	9,101,840	1,748.9	488.0	17,600.8	19,837.6	0.146%	1.150%	1.297%	1.13

Additional analysis was performed where the projects with a benefit-to-cost ratio of less than one were removed from the ESUE totals. The table below shows the results of the analysis where the benefit-to-cost ratios ranged from greater than 2 to greater than 10, resulting in an overall benefit-to-cost ratio of 4.32 for the remaining projects. The total investment was $2.2M or $173k per substation, or $40k per feeder. Total energy savings were estimated at 1.21 percent and 14,534 MWh/yr where 5.2 percent of the savings were from system losses and 94.8 percent from end-use customer load.

Table E-2
ESUE Cost/Benefit Calculations for Systems with a 1.0 or Higher B/C Ratio

Utility	Annual Energy (MWH/yr)	Cost of System Improvements	Line Loss Saved (MWh/yr)	No-Load Loss Saved (MWhyr)	VO Energy Saved (MWh/yr)	Total Energy Savings for Project (MWh/yr)	% Reduction in Annual Energy - Utility	% Reduction in Annual Energy - Customer	% Reduction in Annual Energy - Total	BCR
A	117,575	$298,253	20.4	64.9	690.2	775.4	0.073%	0.587%	0.660%	2.84
B	218,852	$294,638	179.5	35.9	1,209.7	1,425.1	0.098%	0.553%	0.651%	2.97
C	247,600	$150,000	14.4	92.1	2,880.0	2,986.5	0.043%	1.163%	1.206%	14.92
D	87,223	$725,982	155.4	29.9	1,835.0	2,020.3	0.212%	2.104%	2.316%	3.38
E	216,044	$331,800	5.6	29.3	3,430.1	3,464.9	0.016%	1.588%	1.604%	6.51
F	--	--	--	--	--	--	--	--	--	--
G	314,824	$443,662	115.9	18.5	3,728.0	3,862.3	0.043%	1.184%	1.227%	5.81
Totals	1,202,118	$2,244,334	491.1	270.5	13,773.0	14,534.5	0.063%	1.146%	1.209%	4.32

The results of the seven ESUE studies show that the majority (13 out of 19) of the substations and associated feeders (56 out of 79) could be made more efficient by implementing cost-effective system improvements and operating the voltage level in the lower acceptable voltage range. This includes a financial benefit associated with the reduction of customer loads and does not consider the reduction in revenue. Reduction in system losses accounted for 5 percent of the total energy reduction, and end-use load reduction accounted for 95 percent of energy reduction. If voltage reduction were to be performed on the same feeders without system improvements, only six of the substations would have produced energy savings, where only 1.2 percent of the energy savings is from system loss reduction and 98.8 percent is from end-use load reduction. BPA's ESUE program identifies cost-effective improvements and voltage reduction.

F

DISTRIBUTED GENERATION – EMERGING TRENDS CASE STUDY

In January 2009, SAIC finalized the Distributed Renewable Energy Operating Impacts and Valuation Study for Arizona Public Service (APS). The study evaluated the value of solar distribution energy (DE) technologies on the APS transmission and distribution system. Locating solar DE generation near the demand benefits the electric system primarily in two ways:

- It reduces the line losses across the electric system because less energy needs to be transmitted from large central station generation to the location of the demand.
- It reduces the burden on the electric system at peak demands, possibly allowing deferral of transmission and distribution investments.

APS estimates that losses account for 8 percent of energy purchased and generated. Discounting for no-load losses, theft, and company use that are not affected by load reduction, transmission and distribution "series" losses or "load" losses are estimated at 6 percent. Energy loss savings will occur every hour of every year and increase as solar deployment increases.

The study shows that solar DE brings value to APS in both the near term and, increasingly, over the long term. One of the key aspects of the study reflects the fact that solar adoption will likely follow the economic attractiveness. Alternative funding mechanisms, such as third-party leasing, may alter the economic drivers for individual adoption decisions. In the absence of such alternatives, payback period is the primary driver for most technology adoptions, which applies to solar DE adoption as well. As electric rates increase and technology costs decease, the payback period will shorten and deployment will accelerate. The resulting traditional technology "S"-shaped curve for adoption has significant impact on near-term value calculations, particularly in the 2010 and 2015 timeframes. The following chart shows how the solar DE adoption is anticipated to accelerate in the future and the annual MWh savings.

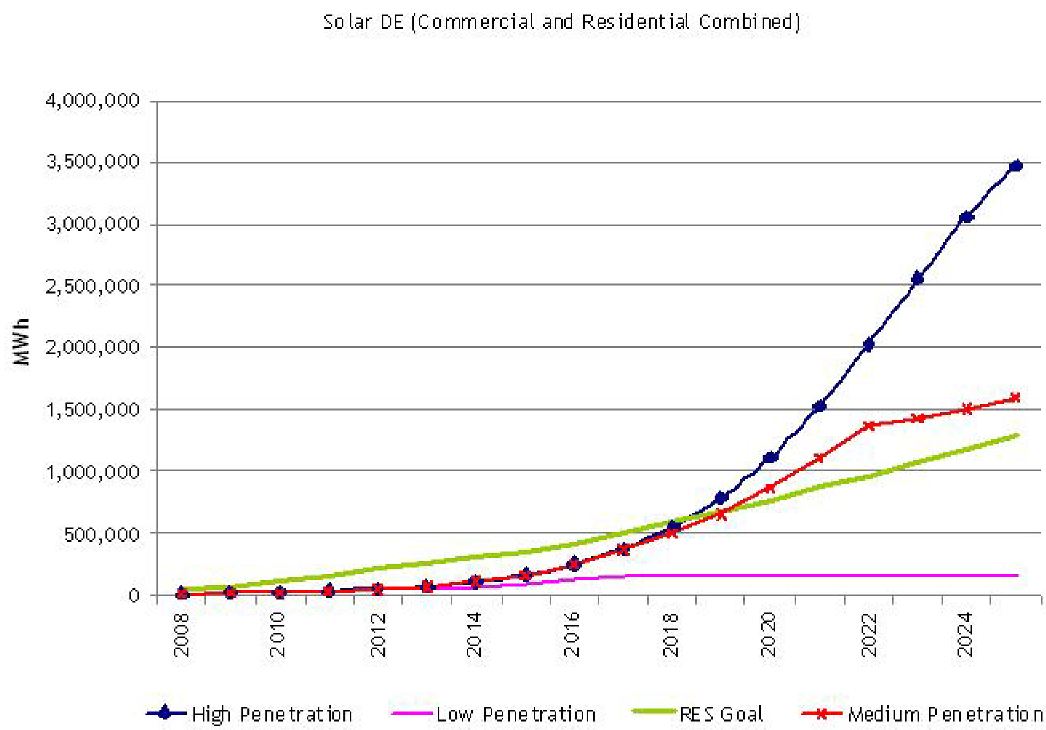


Figure 8-14: Solar DE Penetration and MWh Savings

Using the adoption cases and characterizing the solar DE production, the study developed the capacity impacts on APS. For the distribution system, the market adoption scenarios (low, medium, and high penetration cases) created no real value. This is because the need to meet peak customer load when solar DE is unavailable eliminates most of the potential benefits. However, value for the distribution system can be derived when sufficient solar DE is deployed on a specific feeder. Such deployment can potentially defer distribution upgrade investments, but these solar installations must be located on a specific feeder to reduce a specific overloaded condition. The associated annual savings, which include the impact from carrying costs, are represented in the table below.

Table F-1
Capital Reductions at Distribution Level (2008 $000)

	Distribution System	Carrying Charge (%)	Associated Annual Savings
Target Scenario			
2010	$345	12.06%	$42
2015	$3,335	12.06%	$402
2025	$64,860	12.06%	$7,822

	Distribution System	Carrying Charge (%)	Associated Annual Savings
Single-Axis Sensitivity			
2010	$345	12.06%	$42
2015	$3,450	12.06%	$416
2025	$67,045	12.06%	$8,086

Unlike the distribution system, the specific location of the solar DE was not an impediment to obtaining value for the transmission system. However, there are several other issues that were determined to affect value. First, the long-term planning requirements for transmission facilities made opportunities in 2010 and 2015 unlikely. Initially, a specific load pocket was targeted for transmission relief through solar DE, but the near-term need for additional transmission capacity in that area eliminated this targeted value opportunity. Second, transmission improvements are "lumpy" in nature. A significant number of solar DE installations would be required to aggregate sufficient capacity demand reduction to avoid or defer investments in transmission systems. Therefore, the calculated transmission capacity savings occur only in the last target year (2025) and for the high-penetration case. The carrying costs are represented in the annual savings shown below.

Table F-2
Capital Reductions at Transmission Level (2008 $000)

	Transmission System	Carrying Charge (%)	Associated Annual Savings
High-Penetration Case			
2010	$0	11.84%	$0
2015	$0	11.84%	$0
2025	$110,000	11.84%	$13,024

Solar DE value for the generation system was similar to the transmission system in that the specific location of solar DE was not an impediment to determining capacity savings. Also, similar to the transmission system, capacity cost reductions for the generation system require a significant aggregation of solar DE installations, and benefits occur only in the later years of the study period. However, unlike the transmission system, reductions in generation capital cost were determined to exist for both the medium- and high-penetration cases, as shown in the table below (which incorporates the impacts from the associated carrying costs).

Table F-3
Capital Reductions at Generation Level (2008 $000)

	Generation System	Carrying Charge (%)	Associated Annual Savings
Medium-Penetration Case			
2010	$0	11.79%	$0
2015	$0	11.79%	$0
2025	$184,581	11.79%	$21,762
High-Penetration Case			
2010	$0	11.79%	$0
2015	$0	11.79%	$0
2025	$299,002	11.79%	$35,252

Much of the potential annual saving from solar DE results from APS avoiding the energy produced from solar DE systems. This reduced energy requirement decreases fuel and purchased power requirements and brings associated reductions in line losses and annual fixed O&M costs. Generally, these energy savings were found to exist for all deployment cases, with the exception of reduction in fixed O&M costs for the low-penetration case. Additionally, the specific location of the deployment of solar DE was not a determinant for these value characteristics.

The values determined for the annual energy savings are shown below and are a direct result of the output from the solar DE installations. As more solar DE technology is installed, these savings values will directly increase. Reductions in fixed O&M costs related to the reduction in demand for the dependable generating capacity. The target scenario results (not shown below) are identical to the high-penetration case (as the target scenario is focused on specific locations of solar DE on the distribution system, which impacts the capacity savings but not the energy savings). The single-axis sensitivity shows a slightly higher energy savings resulting from increased production from these units.

Table F-4
Annual Energy and Fixed O&M Savings (2008 $000)

	Solar DE Deployed (MWh)	Annual Energy Loss Savings (MWh)	MWh Savings in Losses/ MWh Solar Generated	Reduction in Losses	Reduction in Fuel/ Purchased Power	Reduction in Fixed O&M Costs	Total Energy Related and Fixed O&M Savings
Low Penetration Case							
2010	15,019	1,829	12.2%	$102	$834	$0	$936
2015	94,782	11,290	11.9%	$501	$5,105	$659	$6,266
2025	157,454	18,607	11.8%	$701	$7,847	$3,728	$12,276

	Solar DE Deployed (MWh)	Annual Energy Loss Savings (MWh)	MWh Savings in Losses/ MWh Solar Generated	Reduction in Losses	Reduction in Fuel/ Purchased Power	Reduction in Fixed O&M Costs	Total Energy Related and Fixed O&M Savings
Medium Penetration Case							
2010	15,798	1,929	12.2%	$108	$872	$0	$980
2015	161,377	19,467	12.1%	$1,034	$9,066	$1,351	$11,450
2025	1,599,924	188,907	11.8%	$8,659	$87,936	$18,946	$115,542
High Penetration Case							
2010	15,798	1,929	12.2%	$108	$872	$0	$980
2015	161,377	19,467	12.1%	$1,034	$9,066	$1,351	$11,450
2025	3,472,412	390,248	11.2%	$14,529	$167,480	$20,965	$202,974
Single-Axis Sensitivity							
2010	16,608	2,031	12.2%	$114	$918	$0	$1,031
2015	167,804	20,262	12.1%	$1,074	$9,504	$1,546	$12,124
2025	3,638,634	407,170	11.2%	$14,925	$173,921	$21,444	$210,290

The results reveal another significant finding of this study; The “law of diminishing returns” applies to solar DE installations. In other words, the more solar DE installed, the less incremental value of each additional solar DE installation. This is illustrated in Table F-4 in the decreased average value of loss reduction between the low-, medium-, and high-penetration cases in the year 2025 (the high-penetration case, with the most solar DE installed in 2025, has the lowest loss savings [MWh] per solar generated [MWh] at 11.2 percent, compared to 11.8 percent for the low-penetration case).

In addition to savings in energy losses, there is also a benefit of avoided losses on capacity, or the ability to defer distribution, transmission, or generation investment. For transmission, the loss savings at the 90 percent confidence interval was 22 percent of the dependable capacity, as calculated in the study.

G
COST/BENEFIT ANALYSIS EXAMPLES

To achieve energy efficiency goals, it is important for utilities to be able to quantify the full costs and benefits associated with capital projects and the reduction of demand and energy requirements. The capital cost of the released capacity does not necessarily appear as a direct immediate cost benefit to the utility. However, the long range cumulative effect of kW and kWh reductions on a utility system does reduce the long-range need for capital investment in facilities to transmit the power reductions.

The value of a peak kW and kWh reduction can vary widely between utilities for some of the following reasons:

- A substantial difference in dollar of gross utility plant per kW or kWh.
- The operation costs for a utility's mix of generation used to meet on- and off-peak requirements.
- If a utility is capacity-constrained, either from by physical plant or contractual requirements.
- Variation in interest rates and taxes. For example, public utilities typically have lower tax burdens and are considered non-profit.

Because there are several approaches to performing a cost/benefit analysis and various ways of presenting the calculations, this appendix includes examples that may be of interest to the participating utilities. Each method is acceptable and arrives at a useable outcome. The following examples are presented:

Example 1:
Demand and Energy Reduction Cost/Benefit Model (EPRI, in collaboration with SAIC)

a. The model includes a sample evaluation for solar distributed generation (DG) on a distribution system. It includes incremental distribution system facility costs (installation and O&M) and benefits (avoided electric system fixed and variable costs). Computed benefits consider avoided generation and/or purchased power energy production costs, avoided generation and transmission facility costs, avoided distribution facility costs, and avoided O&M costs of electric distribution system facilities. Benefit/cost ratios are developed to be used by stakeholders to aid in gauging reasonable, planning-level quantifications of the net system benefits or costs of a certain program or system improvement.

b. The solar DG example outcome results in a net present value (NPV) of $6,332 and a benefit-to-cost ratio of 1.5, which shows the benefits outweigh the costs. Total program costs, over a ten-year period, equate to ~ $17,000, and gross program benefits total ~$27,000 over the same ten-year period.

Example 2:
Street Lighting Evaluation (SAIC)

a. This example considers replacing standard utility system street lighting, such as high pressure sodium (HPS), mercury vapor (MV), and metal halide (MH) with new LED lighting technology on the market. LED lighting is of interest due to increased energy efficiency and life-cycle. However, they are costly.

b. The analysis includes ballast losses, material, and installation costs for the new lights, number of lights in service that will be replaced, hours of operation, failure rate, wholesale demand and energy costs, O&M, and cost of capital.

c. The example outcome shows that the program will break even in costs to benefits in ten years, based on the cumulative NPV cash flow. It can be taken a step further to calculate a benefit-to-cost ratio of 1.14, which shows that the benefits outweigh the costs.

Example 3:
Reconductor – Larger Wire Evaluation (Participating Utility)

a. This example calculates the benefit-to-cost ratio of reconductoring to a larger conductor size. A short-term, four-year, present-worth analysis was performed because there would be other justifications than just losses at the end of the four-year period. The present-worth analysis for “doing nothing” versus upgrading the line “now” was performed.

b. The present-worth analysis tells a similar story to the benefit-to-cost ratio analysis outcome. Both types of analysis show that it’s better to do nothing “now.” The loss improvement is not significant enough to push the project up sooner than the four-year period.

Example 4:
Transfer Single-Phase and Balance Circuit Evaluation (Participating Utility)

a. This example calculates the benefit-to-cost ratio of transferring a single phase to load balance. A short-term, three-year, present worth analysis was performed because there would be other justification than just losses at the end of the three-year period. The present-worth analysis for “doing nothing” versus performing the load transfer was performed.

b. The present-worth analysis tells a different story than the benefit-to-cost ratio analysis outcome. The present-worth analysis shows that it is better to do nothing “now.” The benefit-to-cost ratio is calculated greater than 1, which means performing the improvement “now” is the optimal solution.

Example 1

Demand and Energy Reduction Cost/Benefit Model

(EPRI, in Collaboration with SAIC)

EPRI - Demand and Energy Reduction Cost-Benefit Model

Summary of Avoided Costs and Program/Project Costs

(Nominal $)

Line	*Utility B (Solar): SolarDG Example - Solar PV Rebate*		Units	Const.	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
	General Assumptions:													
1	Inflation	[1]	%	2.20%		2.20%	2.20%	2.20%	2.20%	2.20%	2.20%	2.20%	2.20%	2.20%
2	Discount Rate	[2]	%	5.25%										
	Projected Loads and Pricing:													
3	Forecasted Gross Energy for Load	[3]	MWh		7,493,178	7,586,843	7,681,678	7,777,699	7,874,920	7,973,357	8,073,024	8,173,937	8,276,111	8,379,562
4	Marginal Generation Energy Price	[4]	$/MWh		65.00	66.43	67.89	69.39	70.91	72.47	74.07	75.70	77.36	79.06
5	Forecasted Peak Demand	[5]	MW		1,000.0	1,012.5	1,025.2	1,038.0	1,050.9	1,064.1	1,077.4	1,090.9	1,104.5	1,118.3
6	Demand Price	[6]	$/kW-yr		45.00	45.99	47.00	48.04	49.09	50.17	51.28	52.40	53.56	54.74
	Projected Program Impacts:													
7	Projected Program Energy Reduction	[7]	MWh		10,512.0	15,768.0	21,024.0	26,280.0	31,536.0	36,792.0	42,048.0	47,304.0	52,560.0	57,816.0
8	Projected Program Peak Demand Reduction	[8]	MW		1.2	1.8	2.4	3.0	3.6	4.2	4.8	5.4	6.0	6.6
9	Losses based on Historical Loss Percentage	[9]	MWh	7.50%	561,988	569,013	576,126	583,327	590,619	598,002	605,477	613,045	620,708	628,467
10	Load portion of Losses	[10]	MWh	75.0%	421,491	426,760	432,094	437,496	442,964	448,501	454,108	459,784	465,531	471,350
11	No-Load portion of Losses	[11]	MWh	25.0%	140,497	142,253	144,031	145,832	147,655	149,500	151,369	153,261	155,177	157,117
12	Losses based on Loss Percentage (Resulting from Program)	[12]	MWh	7.50%	561,988	569,013	576,126	583,327	590,619	598,002	605,477	613,045	620,708	628,467
13	Load portion of Losses	[13]	MWh	75.0%	421,491	426,760	432,094	437,496	442,964	448,501	454,108	459,784	465,531	471,350
14	No-Load portion of Losses	[14]	MWh	25.0%	140,497	142,253	144,031	145,832	147,655	149,500	151,369	153,261	155,177	157,117
15	Loss Percentage Change	[15]	%		0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
16	Load portion of Losses	[16]	%		0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
17	No-Load portion of Losses	[17]	%		0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	Avoided Capacity Additions/Purchases:													
18	Generating Unit Capital Costs	[18]	$/MW		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
19	Generating Unit Fixed O&M Costs	[19]	$/MW-yr		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
20	Pass-Through Demand Charge (for Purchases)	[20]	$/kW-yr		45.00	45.99	47.00	48.04	49.09	50.17	51.28	52.40	53.56	54.74
21	Dependable Capacity of Peak Demand Reduction	[21]	%	100.00%										
22	***Avoided Capacity Additions/Purchases Cost***	[22]	**$(000)**		**54.00**	**82.78**	**112.80**	**144.11**	**176.73**	**210.73**	**246.13**	**282.98**	**321.34**	**361.26**
	Avoided Energy Production/Purchase:													
	Marginal Resource Characteristics													
23	Heat Rate	[23]	btu/kWh	0										
24	Fuel Prices	[24]	$/mmBtu		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
25	Variable O&M Costs	[25]	$/MWh		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
26	Emissions Allowance Costs	[26]	$/MWh		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
27	*Marginal Resource Costs*	[27]	$/MWh		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Contract Characteristics													
28	*Tariff or Market Purchase Price*	[28]	$/MWh		65.00	66.43	67.89	69.39	70.91	72.47	74.07	75.70	77.36	79.06
29	***Avoided Energy Production/Purchase Cost***	[29]	**$(000)**		**683.28**	**1,047.47**	**1,427.35**	**1,823.44**	**2,236.27**	**2,666.38**	**3,114.33**	**3,580.70**	**4,066.08**	**4,571.09**
	Avoided System Losses:													
30	***Avoided System Losses Cost***	[30]	**$(000)**		**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**
31	Load portion of Losses Cost	[31]	$(000)		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
32	No-Load portion of Losses Cost	[32]	$(000)		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Avoided Transmission System Improvements:													
33	Load Growth (Organic)	[33]	%			1.3%	1.3%	1.3%	1.2%	1.3%	1.2%	1.3%	1.3%	1.3%
34	Load Reduction (With Project or Program)	[34]	MW		1.20	1.80	2.40	3.00	3.60	4.20	4.80	5.40	6.00	6.60
35	Cost of Transmission Upgrades - Typical Growth	[35]	$/MW		-	-	-	-	-	-	-	-	-	-
36	Typical Load Growth Requiring Upgrades	[36]	MW	5.0										
37	***Avoided Transmission System Improvements Cost***	[37]	**$(000)**		**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**

EPRI - Demand and Energy Reduction Cost-Benefit Model

Summary of Avoided Costs and Program/Project Costs

(Nominal $)

Line	Utility B (Solar): SolarDG Example - Solar PV Rebate		Units	Const.	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
	Avoided Distribution System Improvements:													
38	Capital Budget for Distribution System Improvements - Growth	[38]	$/MW		0	0	0	0	0	0	0	0	0	0
39	***Avoided Distribution System Improvements Cost***	[39]	**$(000)**		**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
	Avoided T&D Improvements O&M Costs:													
40	Avoided O&M Costs associated with Avoided T&D Improvements	[40]	$(000)		0	0	0	0	0	0	0	0	0	0
41	***Avoided O&M Costs:***	[41]	**$(000)**		**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
	Potential Power Market Sales:													
42	Market Value of Surplus Energy	[42]	$/MWh		0	0	0	0	0	0	0	0	0	0
43	***Surplus Energy Sales Value:***	[43]	**$(000)**		**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
44	***Total Gross Program Benefits***	[44]	**$(000)**		**737**	**1,130**	**1,540**	**1,968**	**2,413**	**2,877**	**3,360**	**3,864**	**4,387**	**4,932**
45	***Total Gross Program Benefits***	[45]	**NPV $(000)**		**$19,270**									
	Program Costs													
46	Rebate Costs per Customer	[46]	$		1,250	1,313	1,378	1,447	1,519	1,595	1,675	1,759	1,847	1,939
47	Rebate Customers	[47]	#		2,000	3,000	4,000	5,000	6,000	7,000	8,000	9,000	10,000	11,000
48	Project Costs	[48]	$(000)		0	0.0	0	0	0	0	0	0	0	0
49	**Total Program Costs**	[49]	**$(000)**		**2,500**	**1,313**	**1,378**	**1,447**	**1,519**	**1,595**	**1,675**	**1,759**	**1,847**	**1,939**
50	**Benefit to Cost Ratio**	[50]	**#**		**0.3**	**0.9**	**1.1**	**1.4**	**1.6**	**1.8**	**2.0**	**2.2**	**2.4**	**2.5**
51	**Benefit to Cost Ratio**	[51]	**NPV**		**1.5**									
52	***Net System Benefits***	[52]	**$(000)**		**(1,762.7)**	**(182.2)**	**162.0**	**520.5**	**893.6**	**1,281.7**	**1,685.3**	**2,104.8**	**2,540.6**	**2,993.2**
53	***Net System Benefits***	[53]	**NPV $(000)**		**$6,332**									

EPRI - Demand and Energy Reduction Cost-Benefit Model

Summary of Avoided Costs and Program/Project Costs

(Nominal $)

Line	*Utility B (Solar): SolarDG Example - Solar PV Rebate*	Units	Const.	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020

Footnotes (references to sources may be superseded by user adjustments to key inputs):

[1] Source: Blue Chip Economic Indicators Report, November 2010.
[2] Based on the most recent R. W. Beck standard assumption used to support power supply analyses.
[3] Total Retail Sales plus losses equals Gross Energy for Load. Gross Energy For Load is used to compute baseline and projected losses.
[4] Energy price for resources that are on the margin (or serve the last incremental portion of demand) in the market
[5] Peak Demand represents annual non-coincident peak of the utility or the coincident peak of the utility with their wholesale provider, as appropriate
[6] Demand price for wholesale power purchase contracts expected for utilities that purchase capacity from a third party.
[7] Total annual energy reduction resulting from a Project or a Rebate. Represents an estimate based on the specific characteristics of the Program, as appropriate.
[8] Total annual demand reduction resulting from a Project or a Rebate. Represents an estimate based on the specific characteristics of the Program, as appropriate.
[9] Projection of losses assuming baseline system performance and projected Gross Energy for Load.
[10] Based on allocation of losses for baseline system performance from the Inputs sheet.
[11] Based on allocation of losses for baseline system performance from the Inputs sheet.
[12] Based on projected system performance resulting from the Program, as a function of baseline projected Gross Energy for Load. The difference in losses is valued at the market price for energy
[13] Based on allocation of losses for alternative system performance from the Inputs sheet.
[14] Based on allocation of losses for alternative system performance from the Inputs sheet.
[15] Relative to baseline system performance.
[16] Relative to baseline system performance.
[17] Relative to baseline system performance.
[18] Based on either user defined parameters or assumptions developed by R. W. Beck. Refer to Input sheet for details. Costs may be zeroed out based on their relevance given certain user decisions
[19] Based on either user defined parameters or assumptions developed by R. W. Beck. Refer to Input sheet for details. Costs may be zeroed out based on their relevance given certain user decisions
[20] Same as line 6.
[21] Equal to 100% unless demand reduction is sourced from an intermittently available resource or project (example: solar generation)
[22] Only counts relevant costs based on user decisions in the Inputs sheet.
[23] Based on either user defined parameters or assumptions developed by R. W. Beck. Refer to Input sheet for details.
[24] Based on either user defined parameters or assumptions developed by R. W. Beck. Refer to Input sheet for details.
[25] Based on either user defined parameters or assumptions developed by R. W. Beck. Refer to Input sheet for details.
[26] Based on either user defined parameters or assumptions developed by R. W. Beck. Refer to Input sheet for details.
[27] All-in costs for the selected marginal generating unit that serves the last incremental part of demand
[28] For utilities that purchase power through a third party, whereby costs are a "pass-through" to the utility
[29] Only counts relevant costs based on user decisions in the Inputs sheet.
[30] The difference between baseline losses and losses under the alternative system, valued at the market energy rate
[31] Based on allocation of losses for alternative system performance from the Inputs sheet.
[32] Based on allocation of losses for alternative system performance from the Inputs sheet.
[33] Peak demand growth rates for the baseline system (i.e., prior to the Program).
[34] Same as line 8.
[35] Based on user inputs.
[36] Represents the threshold below which any demand reduction would not be sufficient to avoid the next planned system improvement
[37] Benefits are calculated and assigned to the first year of a 3 year planning window. Equal to zero if threshold for demand reductions was met in the most recent three year planning window
[38] Distribution system improvements are needed for all new loads that come online for a system.
[39] First year costs assume some non-zero growth relative to the year prior to the Base Year.
[40] Ongoing O&M represents an estimate related to both Transmission and Distribution costs in each year, as appropriate
[41] Represents the application of the estimate of ongoing O&M for Transmission and Distribution system improvements (as a percent of plant value) to the total avoided costs (if any) in both categories in each year
[42] Market value of surplus energy may differ from market revenue potential of a specific marginal resource or the energy rate embedded in a specific tariff between a utility and their wholesale provider
[43] Based on total estimate of avoided energy.
[44] "Gross" implies the sum benefits prior to accounting for the intrinsic costs of the Program being analyzed.
[45] Based on assumed discount rate in Inputs sheet.
[46] Based on user inputs.
[47] Based on user inputs.
[48] Based on user inputs.
[49] Only counts relevant costs based on user decisions in the Inputs sheet.
[50] Total program avoided costs (benefits) divided by total program costs; a ratio greater than 1.0 implies that benefits outweigh costs
[51] Benefit to Cost ratio over the life of the project, or the NPV of Gross Benefits divided by the NPV of Total Program Costs.
[52] Total Program Benefits minus total Program Costs.
[53] Based on assumed discount rate in Inputs sheet.

Example 2

Street Lighting Evaluation (SAIC)

Street Lighting Characteristics and Assumptions

Existing Light Types in Service	100W HPS	175W MV	250W HPS	400W MV	400W HPS	1000W MH
No. of Existing Lights in Service - 2011	997	249	306	77	12	8
Rating (Watts) - Existing Lights	100	175	250	400	400	1,000
Ballast Factor	1.15	1.15	1.15	1.15	1.15	1.15
Material Cost per Existing Light	$48.00	$48.00	$170.00	$170.00	$500.00	$317.00
Installation Cost per Existing Light	$32.00	$32.00	$32.00	$32.00	$32.00	$32.00
Capital Cost per Existing Light	$80.00	$80.00	$202.00	$202.00	$532.00	$349.00
Annual Failure Rate - Existing Lights	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%
Proposed Light Type Replacements	28W LED	28W LED	84W LED	84W LED	168W LED	280W LED
Rating (Watts) - Replacement Lights	28	28	84	84	168	280
Ballast Factor	1.08	1.08	1.08	1.08	1.08	1.08
Material Cost per Replacement Light	$536.00	$536.00	$693.00	$693.00	$1,310.00	$2,113.00
Installation Cost per Replacement Light	$32.00	$32.00	$32.00	$32.00	$32.00	$32.00
Capital Cost per Replacement Light	$568.00	$568.00	$725.00	$725.00	$1,342.00	$2,145.00
Annual Failure Rate - Replacement Lights	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%
Net Annual Change in No. of Lights	0	0	0	0	0	0

Other Evaluation Variables

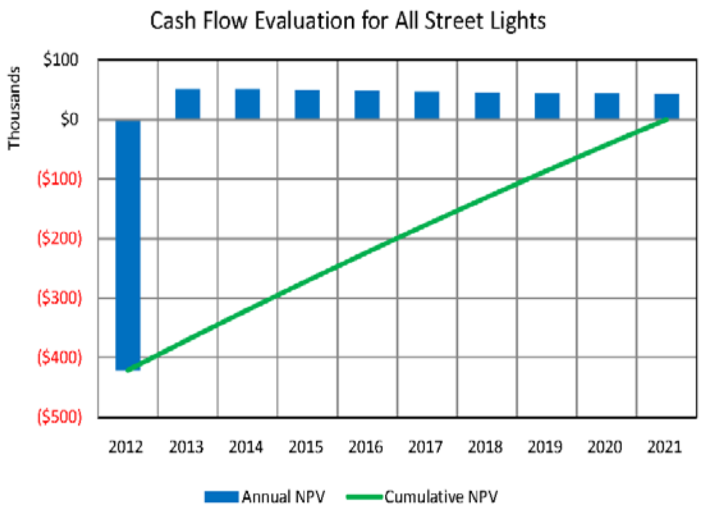
Year Lighting Evaluation Begins	2012
No. of Years to Replace All Lights	1
Minutes After Sunset Lights Turn-On	30
Minutes Before Sunrise Lights Turn-Off	30
EE Grant Reimbursement % of Initial Cost	53%
Wholesale Energy Rate ($/kWh)	$0.06422
Wholesale Demand Rate ($/kW)	$8.24
Annual Freq Lights Are On-Peak (1-12)	0
Annual Power Cost Escalation	2.00%
Annual Capital/O&M Cost Escalation	2.00%
Weighted Avg Cost of Capital	4.50%

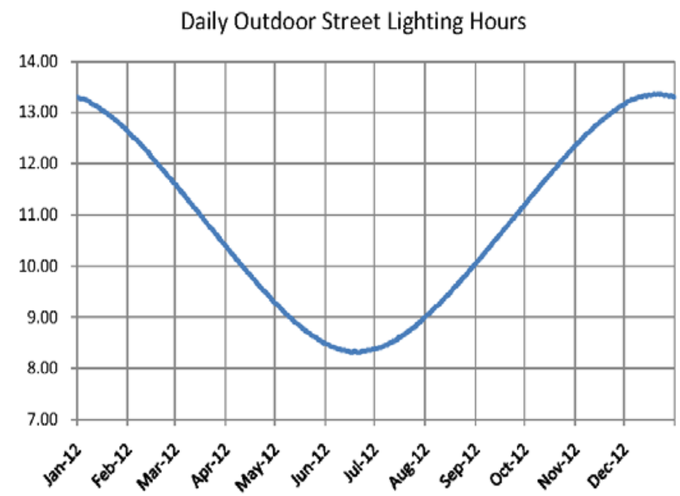
Other Evaluation Assumptions

1. Monthly retail lighting rates are unchanged.
2. Rate study required to determine new monthly rates.
3. EE grants to reimburse capital costs may not exist.
4. Failure rates are mean values stable over svc life.
5. No O&M required other than to replace failed lights.
6. No depreciation or tax related affects are included.
7. Cash flow model does not incude pro forma affects.
8. Wattage and lumen ratings are stable over svc life.
9. Ballast factors provided by Sensus are accurate.
10. Sunrise & sunset times do not vary year to year.
11. Sunrise & sunset times vary with latitude (USNO).
12. Annual lighting hours account for leap years.
13. Escalation rate for capital/O&M costs are the same.
14. Utility customers do not reimburse any initial costs.
15. Freq that lights are on-peak vary with load shape.
16. Sensus recommendations govern all replacements.
17. 175W MV lights are now replaced with 100W HPS.
18. 400W MV lights are now replaced with 250W HPS.
19. ΔWatt on failed light replacements are negligible.
20. All replacements require 2 FTE x $32/hr x 0.50 hr.

Cash Flow Evaluation for All Street Lights

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Total No. of Lights in Service	1,649	1,649	1,649	1,649	1,649	1,649	1,649	1,649	1,649	1,649
No. of Lights Replaced or Installed	1,649	0	0	0	0	0	0	0	0	0
No. of Failures for Existing Lights	48	48	48	48	48	48	48	48	48	48
No. of Failures for Replacement Lights	16	16	16	16	16	16	16	16	16	16
Avoided Capacity (kW)	225.9	225.9	225.9	225.9	225.9	225.9	225.9	225.9	225.9	225.9
Avoided Energy (kWh)	894,214	891,590	891,590	891,590	894,214	891,590	891,590	891,590	894,214	891,590
Avoided Wholesale Power Cost	$57,424	$58,401	$59,569	$60,760	$62,158	$63,215	$64,479	$65,769	$67,282	$68,426
Avoided Failed Light O&M Cost	($4,534)	($4,625)	($4,717)	($4,812)	($4,908)	($5,006)	($5,106)	($5,208)	($5,312)	($5,419)
Capital Cost to Replace or Install Lights	($474,393)	$0	$0	$0	$0	$0	$0	$0	$0	$0
Net Cash Flow	($421,503)	$53,776	$54,852	$55,949	$57,250	$58,209	$59,373	$60,561	$61,969	$63,007
Net PV Cash Flow	($421,503)	$51,460	$50,229	$49,028	$48,008	$46,710	$45,592	$44,502	$43,576	$42,398
Cumulative Net PV Cash Flow	($421,503)	($370,042)	($319,813)	($270,785)	($222,778)	($176,068)	($130,475)	($85,974)	($42,398)	($0)





Example 3

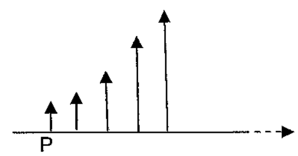
Reconductor – Larger Wire Evaluation (Participating Utility)

Reconductor - Larger Wire

Existing (Do nothing):

13.2kV 13.2kV

i= 7.30%



growth rate	5.00%	
loss growth	10.25%	
2008 Pk Loss	796	kW
2008 Losses	2,266,212	kwHr

	Annual Losses (KWHr)	Cost	Year	PW Factor	Peak Loss (KW)	Loss Factor	
							0.325
2008	2,266,212	$217,392		$217,392	796		
2009	2,498,499	$253,343	1	$236,107	877.59		
2010	2,754,595	$282,837	2	$245,661	967.54		
2011	3,036,941	$316,012	3	$255,802	1066.72	Cost of Losses	
2012	3,348,227	$353,505	4	$266,684	1176.05	PW	$1,221,648

Note: n = 4 years is the number of years until the #4 conductor would be overloaded and work would be forced for other purpose.

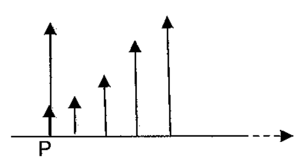
i=7.3%, which is the discount rate after the overall weighted cost of capital ordered by PSC

Reconductor the #2 to 3/0

13.2kV

#2 to 3/0 - 1000 feet

i=7.3%



growth rate	5.00%	
loss growth	10.25%	
2008 Pk Loss	796	kW
2008 Losses	59,905	kwHr

2008 Project Cost:
$160,000

	Annual Losses (KWHr)	Cost	Year	PW Factor	Peak Loss (KW)	Loss Factor	
							0.325
2008	2,266,212	$217,392		$217,392	796		
2009	2,498,499	$253,343	1	$236,107	877.59		
2010	2,754,595	$282,837	2	$245,661	967.54		
2011	3,036,941	$316,012	3	$255,802	1066.72	Cost of Losses	
2012	3,348,227	$353,505	4	$266,684	1176.05	PW	$1,221,648
						PW Total	$1,381,648

From Just a Losses Point of View, Comparing the "Do Nothing Alternative" to the Line Upgrade using the Present Worth Method, we are better doing nothing at this point.

$1,221,648 < $1,381,648

Using the Benefit/Cost Analysis Appproach:

Do Nothing		Annual
	Cost:	Nothing
	Losses:	$363,110
Project		
	Cost:	$47,557
	Losses:	$363,110

Cost =	$47,557
Benefits=	$0

B/C Ratio= 0

Since B/C < 1, this project is NOT justified.

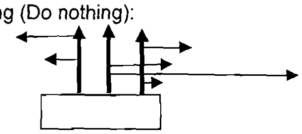
Example 4

Transfer Single-Phase and Balance Circuit Evaluation

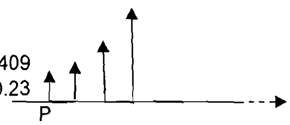
(Participating Utility)

Transfer Single-Phase & Balance Circuit

Existing (Do nothing):



i=7.69%



P

n=3

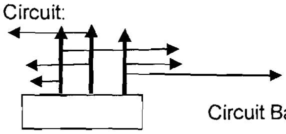
growth rate	7.00%	Ld Factor	0.4409
loss growth	14.49%	"C" Value	0.23
2008 Pk Loss	174 kW		
2008 Losses	382,721 kwHr		

	Annual Losses (KWHr)	Cost	Year	PW Factor	Peak Loss (KW)	Loss Factor
						0.251089464
2008	382,721	$38,024		$38,024	174	
2009	438,177	$46,087	1	$42,796	199.21	
2010	501,669	$53,604	2	$46,222	228.08	
2011	574,360	$62,404	3	$49,968	261.13	Cost of Losses
					PW	$177,010

Note: n = 3 years is the number of years until the circuit will exceed its 600 Amp rating

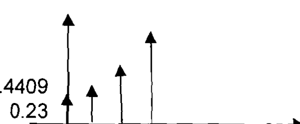
i=7.69%, which is the discount rate after the overall weighted cost of capital ordered by PSC

Balance Circuit:



Circuit Balanced

i=7.69%



P

n=3

growth rate	7.00%		
loss growth	14.49%		
2008 Pk Loss	127 kW		
2008 Losses	279,342 kwHr		
		Ld Factor	0.4409
		"C" Value	0.23

2008 Project Cost:
6,000

	Annual Losses (KWHr)	Cost	Year	PW Factor	Peak Loss (KW)	Loss Factor
						0.251089464
2008	279,342	$27,753		$27,753	127	
2009	319,819	$33,638	1	$31,236	145.40	
2010	366,160	$39,125	2	$33,736	166.47	
2011	419,217	$45,548	3	$36,471	190.59	Cost of Losses
					PW	$129,197
					PW Total	$135,197

From Just a Losses Point of View, Comparing the "Do Nothing Alternative" to the Line Upgrade using the Present Worth Method, we are better doing nothing at this point.

$177,010 > $135,197

Using the Benefit/Cost Analysis Appproach:

		Annual
Do Nothing		
	Cost:	Nothing
	Losses:	$68,302
Project		
	Cost:	$2,315
	Losses:	$49,852

Cost =	$2,315
Benefits=	$18,449

B/C Ratio= 7.96882175

The B/C > 1 and is therefore justified from just a losses point of view.

H
REDUCING POWER FACTOR COST

Department of Energy, Motor Challenge Program Fact Sheet:
Reducing Power Factor Cost

FACT SHEET

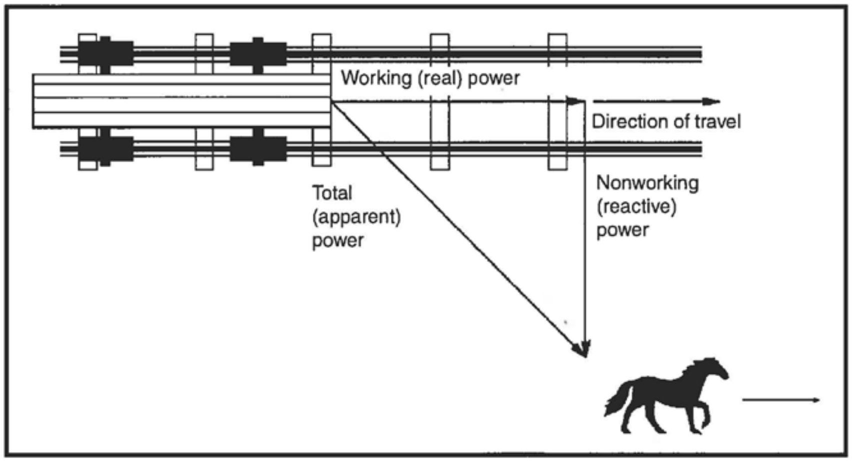
a Program of the U.S. Department of Energy

MOTOR CHALLENGE

REDUCING POWER FACTOR COST

Low power factor is expensive and inefficient. Many utility companies charge you an additional fee if your power factor is less than 0.95. Low power factor also reduces your electrical system's distribution capacity by increasing current flow and causing voltage drops. This fact sheet describes power factor and explains how you can improve your power factor to reduce electric bills and enhance your electrical system's capacity.

What is Power Factor?



To understand power factor, visualize a horse pulling a railroad car down a railroad track. Because the railroad ties are uneven, the horse must pull the car from the side of the track. The horse is pulling the railroad car at an angle to the direction of the car's travel. The power required to move the car down the track is the working **(real)** power. The effort of the horse is the total **(apparent)** power. Because of the angle of the horse's pull, not all of the horse's effort is used to move the car down the track. The car will not move sideways; therefore, the sideways pull of the horse is wasted effort or nonworking **(reactive)** power.

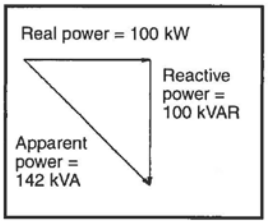
The angle of the horse's pull is related to power factor, which is defined as the ratio of real (working) power to apparent (total) power. If the horse is led closer to the center of the track, the angle of side pull decreases and the real power approaches the value of the apparent power. Therefore, the ratio of real power to apparent power (the power factor) approaches 1. As the power factor approaches 1, the reactive (nonworking) power approaches 0.

$$\textit{Power Factor} = \frac{\textit{Real Power}}{\textit{Apparent Power}}$$

The energy savings network

Plug into it!

For example, using the power triangle illustrated below, if



Real power = 100 kW
and
Apparent power = 142 kVA
then
Power Factor = 100/142 = 0.70 or 70%.

This indicates that only 70% of the current provided by the electrical utility is being used to produce useful work.

Cause of Low Power Factor

Low power factor is caused by inductive loads (such as transformers, electric motors, and high-intensity discharge lighting), which are a major portion of the power consumed in industrial complexes. Unlike resistive loads that create heat by consuming kilowatts, inductive loads require the current to create a magnetic field, and the magnetic field produces the desired work. The total or apparent power required by an inductive device is a composite of the following:

- Real power (measured in kilowatts, kW)
- Reactive power, the nonworking power caused by the magnetizing current, required to operate the device (measured in kilovars, kVAR)

Reactive power required by inductive loads increases the amount of apparent power (measured in kilovolt amps, kVA) in your distribution system. The increase in reactive and apparent power causes the power factor to decrease.

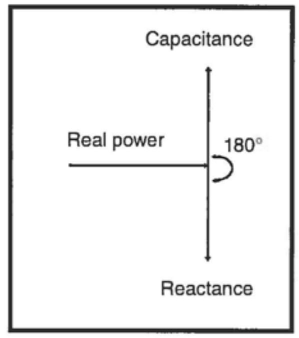
Why Improve Your Power Factor?

Some of the benefits of improving your power factor are as follows:

- Your utility bill will be smaller. Low power factor requires an increase in the electric utility's generation and transmission capacity to handle the reactive power component caused by inductive loads. Utilities usually charge a penalty fee to customers with power factors less than 0.95. You can avoid this additional fee by increasing your power factor.
- Your electrical system's branch capacity will increase. Uncorrected power factor will cause power losses in your distribution system. You may experience voltage drops as power losses increase. Excessive voltage drops can cause overheating and premature failure of motors and other inductive equipment.

3

Correcting Your Power Factor



Some strategies for correcting your power factor are:

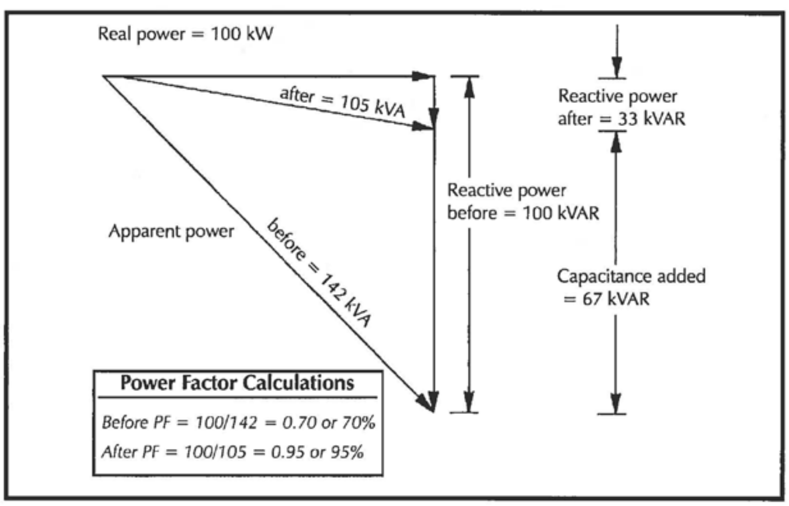
- Minimize operation of idling or lightly loaded motors.
- Avoid operation of equipment above its rated voltage.
- Replace standard motors as they burn out with energy-efficient motors. Even with energy-efficient motors, however, the power factor is significantly affected by variations in load. A motor must be operated near its rated capacity to realize the benefits of a high power factor design.
- Install capacitors in your AC circuit to decrease the magnitude of reactive power.

As shown in the diagram at right, reactive power (measured in kVARs) caused by inductance always acts at a 90° angle to real power. Capacitors store kVARs and release energy opposing the reactive energy caused by the inductor. This implies that inductance and capacitance react 180° to each other. The presence of both in the same circuit results in the continuous alternating transfer of energy between the capacitor and the inductor, thereby reducing the current flow from the generator to the circuit. When the circuit is balanced, all the energy released by the inductor is absorbed by the capacitor.

In the diagram below, the power triangle shows an initial 0.70 power factor for a 100-kW (real power) inductive load. The reactive power required by the load is 100 kW. By installing a 67-kW capacitor, the apparent power is reduced from 142 to 105 kVA, resulting in a 26% reduction in current. Power factor is improved to 0.95.

In the "horse and railcar" analogy, this is equivalent to decreasing the angle the horse is pulling on the railcar by leading the horse closer to the center of the railroad track. Because the side pull is minimized, less total effort is required from the horse to do the same amount of work.

Capacitor suppliers and engineering firms can provide the assistance you may need to determine the optimum power correction factor and to correctly locate and install capacitors in your electrical distribution system.



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About Motor Challenge

Motor Challenge is a partnership program between the U.S. Department of Energy and the nation's industries. The program is committed to increasing the use of energy-efficient, industrial electric motor systems and related technologies.

The program is wholly funded by the U.S. Department of Energy and is dedicated to helping industry increase its competitive edge, while conserving the nation's energy resources and enhancing environmental quality.

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For More Information

Contact the Motor Challenge Information Clearinghouse: 1-800-862-2086. The Motor Challenge Information Clearinghouse is your one-stop resource for objective, reliable, and timely information on electric motor-driven systems.

Access the Motor Challenge website on the Internet at www.motor.doe.gov.

DOE/GO-10096-286

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