Evaluating Distribution System Losses Using Data from Deployed AMI and GIS Systems

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***Abstract* -- Distribution system losses are a reality due to the physics associated with various system components that make up any power system. Techniques for analyzing losses are not new but have primarily focused on evaluating system losses during certain peak demand periods due to limitations on available data. Such "traditional" analyses estimate energy losses using industry accepted approaches that rely heavily on assumptions and that focus only on peak and average demands on major system components. Another potential shortcoming of a traditional loss analysis is the level of system detail evaluated. A gross analysis in terms of system components such as substation power transformers, distribution lines, distribution transformers, secondary conductors, etc. is typical. The disadvantage is that the relative contribution of various system components to the overall system losses may not be defined to the level required to truly evaluate mitigation techniques, especially when time periods other than peak demand times are being evaluated.**

Given the limitations of traditional loss evaluations, this paper will explore enhanced loss evaluation techniques utilizing interval load data collected from a deployed Advanced Metering Infrastructure (AMI) system and detailed system data from an available Geographic Information System (GIS). The test case system used to present this approach was a distribution cooperative with these systems presently in place.

I. Introduction

Distribution system losses have long been of interest to electric utilities due to the lost revenue from power and energy being purchased (or generated as the case may be) but not sold. Losses are typically quantified in terms of a percentage of purchases, and calculated using the following formula:

$$Percent\ Losses = \frac{(kWh\ Purchases\ -\ kWh\ Sales)}{kWh\ Purchases}\ x\ 100 \qquad (1)$$

Typical distribution system losses might range from 6 to 10%, depending on the characteristics of the system, the equipment installed and the operating philosophies of the utility. Traditionally, losses have been calculated by simply comparing purchases from power bills to sales recorded from the meters installed at each service location. Several problems and shortcomings, however, are typically encountered with this approach. First, lining up the time periods for the purchases and sales is a challenge due to meter readings taking place across multiple billing cycles that do not necessarily correspond with the same time period that the wholesale power bills represent. Second, if meter readings are obtained from customers self-reading the meter, error is introduced to the loss calculation from both honest mistakes and from customers falsely reporting meter reads. Both of these issues can be mitigated to some degree by looking at losses on an annual basis and putting forth some extra effort to correctly obtain purchase and sales information for roughly the same time period. Successfully achieving the preceding, though, at best results in a determination of total system energy losses over a given year. This calculated value is a good indicator of overall system efficiency and lost revenue due to losses, but little more.

An additional step to determine demand losses during peak demand time periods can be completed using an engineering model of the system; however, electrical models available have typically been very gross representations of the system used for system planning purposes. While these models may be perfectly adequate for system planning, they are typically lacking when attempting to quantify losses and identify contributions to losses from each system component.

Today's world of hourly energy markets and transmission congestion charges increases the desirability of obtaining more accurate knowledge of when losses are being incurred on the system and the magnitude of those losses during different costing periods. The utility industry has also placed a high level of importance on improving energy efficiency. The techniques discussed in this paper should yield a more accurate picture of both demand and energy losses by system component during any timeframe of interest. The advanced techniques presented are made possible with data obtained from AMI and GIS systems. Otsego Electric Cooperative (Otsego), headquartered in Hartwick, NY, has both of these systems presently in place and their Richfield substation was chosen as the test case to present these techniques.

II. AMI and GIS Data Contributions to Loss Evaluations

Loss evaluations are very much dependent on the data available. AMI and GIS systems can provide a wealth of information (sometimes too much!) that can be beneficial in evaluating when and where losses are being incurred. Proper management of this data is critical, however, to successfully realizing these benefits.

A. GIS Data

The database behind the GIS can include virtually any type of data that a utility wishes. The data that is most useful with loss evaluations is the detailed information on each piece of equipment and the conductors themselves. Correct electrical connectivity of each system component is also highly desirable to create electrical models of the system by extraction of the data from the GIS database in a format that can be imported into a commercially available engineering analysis software package.

The GIS database for the test case system included information down to the meter level. A detailed engineering model was created using this database that accurately represents the system from the source to each individual meter, including distribution transformers and secondary/service conductors. The test case used in this analysis was the Otsego Electric Cooperative Richfield substation area. The following summarizes the test case area:

- Substation
  - 44 kV to 12.47/7.2 kV
  - (3) – 833 kVA transformers
  - (3) – 167 kVA bus regulators
  - (2) – exit feeders
- Primary distribution system phasing
  - 61.7 mi of single-phase
  - 2.6 mi of “V”-phase
  - 12.2 mi of three-phase
- Primary distribution system conductors
  - 36.4 mi of 1/0 ACSR
  - 2.2 mi of #2 ACSR
  - 23.9 mi of #4 ACSR
  - 14.0 mi of 6A CWC
- Distribution transformer – accounts served
  - 308 transformers serving one account
  - 41 transformers serving two accounts
  - 9 transformers serving three + accounts
- Distribution transformer sizes
  - 5 kVA = 6
  - 7.5 kVA = 4
  - 10 kVA = 273
  - 15 kVA = 56
  - 25 kVA = 15
  - 37.5 kVA = 2
  - 50 kVA = 3 (for one three-phase acct)
- Secondary conductor
  - Average length of 105 feet per service
  - Majority of conductor #2 or 1/0 overhead triplex
- Customer accounts
  - 459 accounts (predominately residential)
  - (93) – 175W mercury vapor lights

B. AMI Data

A fully deployed AMI system can be used to obtain meter readings from the end-use revenue meters installed in the field for any timeframe of interest. Typically, meter readings are received at the central office once per day for the previous 24 hours of usage. Additionally, interval load data for every hour can be obtained. Collecting this amount of data is not without its challenges. Hardware and software limitations may exist that affect the number of meters and the timeframe in which interval load data can be collected. Storing and managing the data can be cumbersome and time consuming. Missing data reads occur and need to be addressed. Meter multipliers must be properly accounted for and applied.

Assuming that the challenges can be overcome, interval load data collected from an AMI system can benefit loss evaluations in several ways:

- Load data associated with a particular account can be used to accurately calculate secondary and distribution transformer load losses. Where multiple accounts are served from the same transformer or via a shared secondary conductor, the individual meter reads will need to be aggregated to determine the total load imposed.
- Usage (sales) at each of the end-use meters can be aggregated and compared to the delivered energy (purchases) to determine total losses for each substation. If a SCADA system is installed with revenue-grade accuracy, further break down of losses can be achieved by feeder or along parts of a feeder.

Aggregating load data for comparison purposes with purchases or deliveries can be a difficult task. Any missing data, or data that has to be estimated, can introduce error into the loss calculation. A simple example may best illustrate this point. Assume that 100 meters are installed along a particular feeder. For a given time period, it is known that 110 kWh were delivered from data collected from a SCADA system with revenue-grade accuracy. If each meter used 1 kWh for the same time period, the calculated losses on a percent basis are (110 kWh – 100 kWh) ÷ 110 kWh = 9.1%. For every meter that data is missing and not accounted for, the calculated losses would be increased by 1 kWh, or 0.9% (1 ÷ 110). This amount of error is not insignificant. Therefore, it is critical that all data is accurately accounted for, including unmetered usage such as security lights and utility-owned equipment, for the results of this type of analysis to be beneficial.

Hourly interval load data was collected over approximately a 5 day time period for each meter in the test case area for the analysis presented in this paper. Unmetered security light usage was estimated using metering data collected for a representative 175W mercury vapor light.

III. MONTHLY LOSS CALCULATIONS

A first step to using available AMI data in more accurately calculating system losses could be to align the sales and purchases timeframes. This can be accomplished by comparing the daily meter read from the AMI system for the last day of the wholesale power billing period to the daily meter read from the last day of the previous wholesale power billing period. Subtracting the latter value from the former value will yield the sales over the same timeframe as the wholesale power bill. Assuming that deliveries to each substation are available from the wholesale power supplier, system losses for each substation area can be more precisely determined for each month. Again, data for every meter and all unmetered usage must be accounted for in this calculation. If a SCADA system is deployed with revenue-grade metering, this calculation could be applied as information is available, such as to individual feeders or at various points along a feeder.

A separate process to accomplish this calculation could be created, or the existing billing system could be used to automatically generate a monthly report. In the case of Otsego Electric Cooperative, the billing system is used to generate a monthly report. For example, using this process it was determined that during the month of November 2009, total sales in the Richfield substation area were 391,735 kWh and total deliveries to the Richfield substation (purchases) were 428,976 kWh. Total losses were therefore 37,241 kWh (428,976 – 391,735) or 8.7% (37,241 ÷ 428,976).

In the monthly loss calculation just described, it is required to aggregate the usage for each individual meter by substation area, or feeder as the case may be. It is therefore very important to ensure that each individual meter is associated with the correct substation and feeder. Changes in substation boundaries that are not accounted for will lead to error in the calculation.

While this process yields more insight into energy losses for a given substation area during a given month, it does not help to determine losses during any specific hours of interest, such as peak times or during high cost periods. This process also does not help to ascertain where exactly the losses are coming from and how best to lower these losses.

IV. HOURLY LOSS CALCULATIONS

Greater insight into where losses are being incurred, and the magnitude of those losses at specific time periods of interest, can be obtained through rigorous loss calculations for individual hours (also known as demand losses). The flow diagram in Fig. 1 describes the steps to complete these calculations. This process was used to calculate losses by system component for each hour of interval load data obtained for the test case area. The details of the calculations and the results are presented in the following sections of this paper.

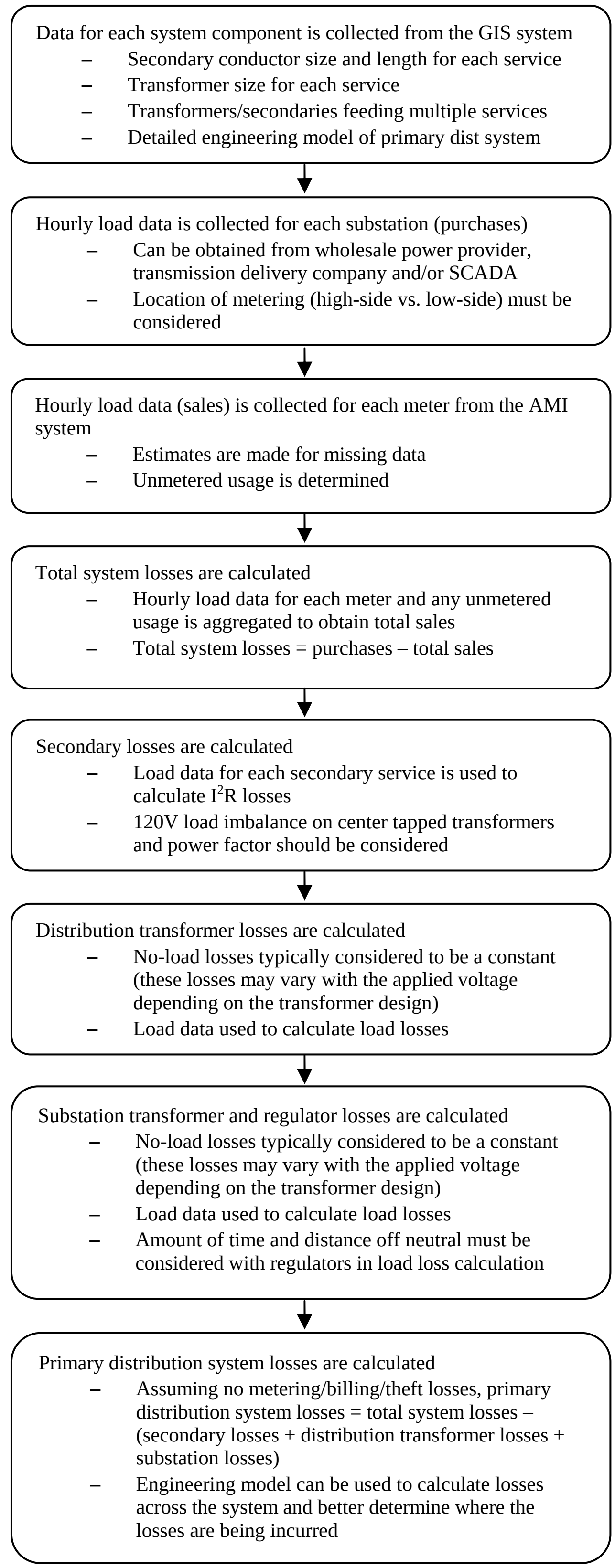

Fig. 1 Detailed hourly loss evaluation flow diagram

A. Load Data Collected

Hourly interval load data was collected from the AMI system for each meter in the Richfield substation area for a 125 hour time period. Over this time period, 99.5% of the data was received. Several missing hours of data existed for a few meters, and no data was available for one meter. Estimates for missing data were made based on usage in similar hours and/or from similar accounts. Total sales for the time period were determined to be 76,948 kWh.

Hourly real and reactive power deliveries to the Richfield substation were collected for the same timeframe from the wholesale power provider. A summary of this data follows:

- Minimum load = 401 kW
- Maximum load = 982 kW
- Average load = 668 kW
- Total energy delivered = 83,542 kWh

The historical peak load on this substation is 1,315 kW and the historical annual average load is approximately 600 kW.

Total losses for every hour in the time period analyzed were calculated by subtracting the aggregated sales data from the purchase data. Purchases, sales and total system losses for the time period are shown in Fig. 2. Total energy losses were calculated to be 6,594 kWh, or 7.9% of purchases.

B. Secondary Losses

Secondary conductor losses are due to load current (I) flowing through the resistance (R) of the conductor, and are calculated using the formula I^2R. Resistance values for various size and type of conductors are published by the manufacturer. Current is calculated using the hourly load data for each meter. Secondary conductors for single-phase 120/240 V services being supplied by a center tapped transformer are triplexed conductors that consist of two “hot” legs and a neutral. Assumptions relating to voltage received and 120V load imbalance are required in the loss calculation to determine how much current is flowing through each conductor. Assumptions related to power factor are required as well. A sensitivity analysis was performed to determine how much effect each of these variables had on the calculated results. The impact was determined to be minor.

Secondary losses were calculated for each service in the Richfield substation area for every hour in the time period analyzed. Nominal 120V was assumed, and reasonable assumptions were used for 120V load imbalance (20% was assumed) and power factor (95% was assumed).

Total secondary energy losses for the time period analyzed were calculated to be 651 kWh, or 0.8% of purchases. On a percentage basis, the demand losses calculated for any given hour ranged from a low of 0.4% to a high of 1.1% of purchases.

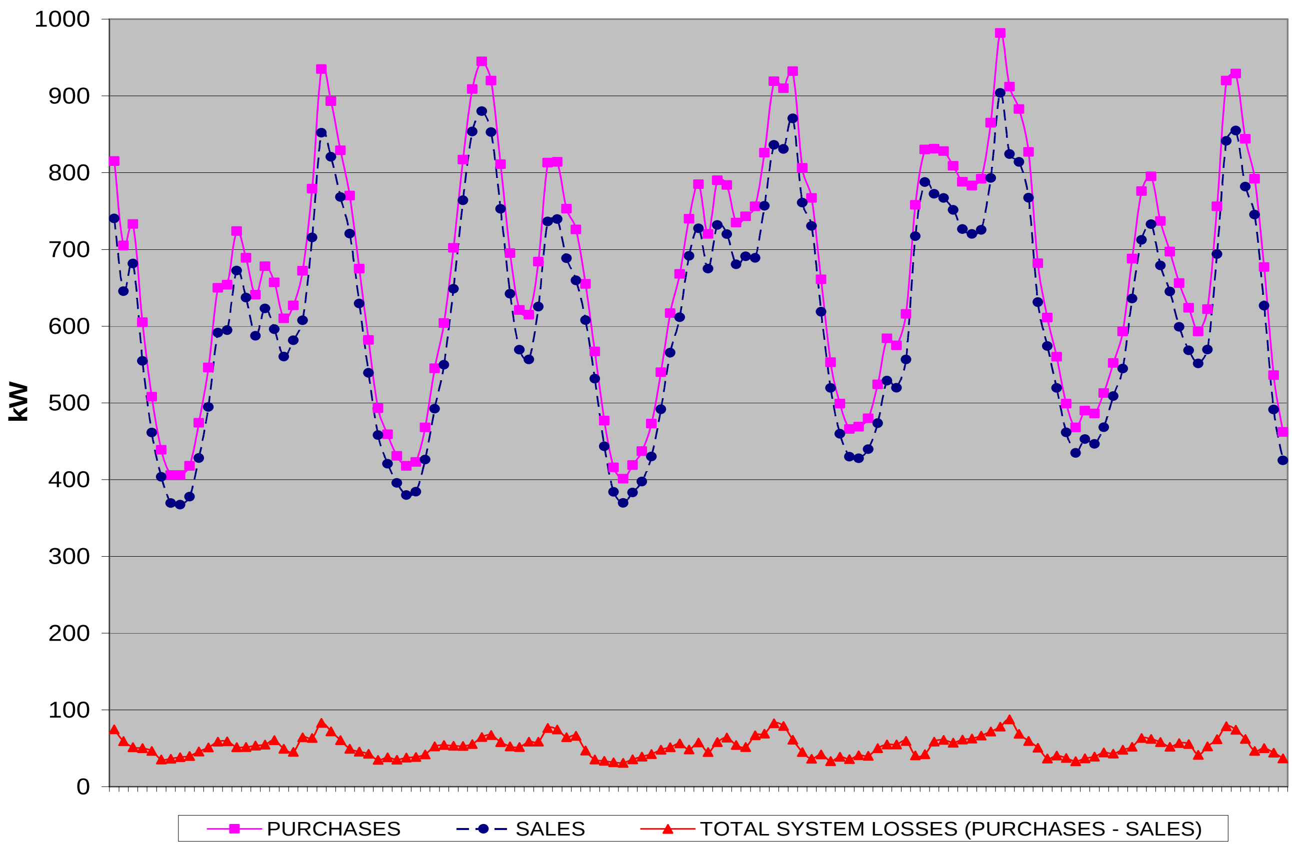

Fig. 2 Richfield substation hourly purchases, sales and total system losses

C. Distribution Transformer Losses

Distribution transformer losses consist of load losses (also referred to as copper or winding losses) and no-load losses (also referred to as iron or core losses). No-load losses are typically considered a constant as they do not vary with the load imposed on the transformer, but they may vary exponentially with the voltage applied. Load losses vary with the square of the current through the transformer winding.

1) No-Load Losses

For the purpose of this analysis, no-load losses were considered to be constant. Accurate test records for each distribution transformer installed in the Richfield substation area were not available; therefore, assumptions as to the rated no-load loss value of each transformer were required to be made. No-load loss values used in the analysis are shown in Table 1. An attempt was made to use values that are more representative of Completely Self Protected (CSP) transformers with an average age of 20 years, as this is generally indicative of the distribution transformers installed in the Richfield substation area.

Total distribution transformer energy no-load losses for all transformers installed in the Richfield substation area were calculated to be 17.41 kW per hour, for a total of 2,176 kWh or 2.6% of purchases over the time period analyzed. On a percentage basis, the demand losses calculated for any given hour ranged from a low of 1.8% to a high of 4.3% of purchases.

2) Load Losses

Load losses for each distribution transformer installed in the Richfield substation area were calculated for every hour in the time period analyzed. Again, assumptions as to the rated load loss value of each transformer were required to be made, and are shown in Table 1. Transformer load losses are reported by the manufacturer based on the rated voltage and output of the transformer. To determine the load losses for any particular load value other than the nameplate, the following formula is used:

$$\mathit{Transformer\,Load\,Loss} = \left[\frac{\mathit{kVA\,Load}}{\mathit{Rated\ Transformer\,kVA}}\right]^2 \times \mathit{Rated\ Load\ Loss} \qquad (2)$$

Total distribution transformer energy load losses for all transformers installed in the Richfield substation area were calculated to be 527 kWh or 0.6% of purchases over the time period analyzed. On a percentage basis, the demand losses calculated for any given hour ranged from a low of 0.3% to a high of 0.9% of purchases.

It can be seen from the above that the transformer no-load losses are significantly higher than the transformer load losses for this particular time period and substation area. This is in large part due to the majority of the distribution transformers being loaded to levels well below nameplate. However, an accurate conclusion regarding the adequacy of transformer loading levels cannot be made based solely on the limited time period analyzed.

TABLE 1
TRANSFORMER RATED LOSS ASSUMPTIONS

Size (kVA)	No-Load Losses (W)	Load Losses (W)
5	20	75
7.5	30	110
10	45	220
15	60	285
25	85	450
37.5	110	515
50	140	615

D. Substation Losses

Substation transformer and voltage regulator losses are calculated by a method similar to that described for distribution transformer losses. One important difference for voltage regulators is that the amount of time and distance off of neutral has to be taken into account in the load loss calculations. No-load and load losses were calculated for the substation transformers and regulators installed at the Richfield substation. It should be noted that single-phase transformers are installed at this substation rather than a three-phase transformer, and that bus regulation is present rather than individual feeder regulation.

Total substation transformer and regulator energy no-load losses for the Richfield substation were calculated to be 9.9 kW per hour, for a total of 1,238 kWh or 1.5% of purchases over the time period analyzed. On a percentage basis, the demand losses calculated for any given hour ranged from a low of 1.0% to a high of 2.5% of purchases.

Total substation transformer and regulator energy load losses for the Richfield substation were calculated to be 306 kWh or 0.4% of purchases over the time period analyzed. On a percentage basis, the demand losses calculated for any given hour ranged from a low of 0.2% to a high of 0.5% of purchases.

It can be seen from the above that the substation no-load loss values are significantly higher than the substation load losses for this particular time period. This is in large part due to the substation transformers being loaded to levels well below nameplate. Again, an accurate conclusion regarding the adequacy of transformer loading levels cannot be made based solely on the limited time period analyzed.

A certain amount of unmetered usage is present in most substations to provide power for utility equipment. This usage should be taken into account when calculating total system losses. Additionally, it is important to note whether the metering installed at the substation is installed on the high or low voltage side of the substation transformer(s).

E. Primary Distribution System Losses

Primary distribution losses are mainly comprised of I^2R losses associated with the primary distribution system conductors. Voltage regulators installed on the system are also a source of losses that must be considered.

Given the analysis completed thus far, if no metering/billing/theft losses are present, the primary distribution system losses can be calculated by simply subtracting the sum of all other sources of losses from the total system losses using the following formula:

Primary distribution system losses = total system losses – (secondary losses + distribution transformer losses + substation losses) (3)

Using the formula above, primary distribution system energy losses were calculated to be 1,696 kWh or 2.0% of purchases over the time period analyzed. On a percentage basis, the demand losses calculated for any given hour ranged from a low of 1.4% to a high of 2.8% of purchases.

To verify that the above calculated values were reasonable, and to better ascertain where the primary distribution system losses are coming from, the engineering model created from the GIS database was used to calculate primary distribution system demand losses at various load levels. Rather than model 125 hours worth of data, ten models were run over a range of loads experienced during the time period analyzed. Primary distribution system demand losses were estimated for the remaining hours based on a regression equation fit to capture the relationship between primary distribution system demand losses and the load at the Richfield substation. The results of this analysis calculated total primary distribution system energy losses to be 1,729 kWh or 2.1% of purchases over the time period analyzed. Since the loss values calculated from each of these methods were remarkably close, it was felt that the assumptions used in the loss calculations were reasonable.

F. Summary of Results

Table 2 presents a summary of the calculated losses by system component for the time period analyzed. Transformer no-load losses and primary distribution system losses are the dominant components. It stands to reason then that loss mitigation techniques that focus on these two areas should be given special attention as that is where the most gains may be found.

Fig.3 graphs the percent losses by component for a range of loads experienced during the time period analyzed and for the historical peak hour that occurred outside this time period. It is interesting to note the bowl shape of the bar graph. Since a large amount of losses are I^2R losses, it is obvious that the total magnitude of losses on a kW or kWh basis is greater at higher load levels. This relationship can clearly be seen in Fig. 1. However, on a percentage of purchases basis, this is not the case. In fact, due to the amount of transformer no-load losses, it is typical to find that the percent losses are just as great, if not greater, at the lowest load levels. Similarly, when calculating total system losses on a monthly basis, it is not uncommon to find that the losses on a percentage basis are just as high during shoulder months as they are during months with higher usages.

TABLE 2
SUMMARY OF CALCULATED RESULTS

		TOTAL	MIN	MAX
Purchases	(kWh)	83,542	401.0	982.0
Sales	(kWh)	76,948	367.6	903.8
Total System Losses	(kWh)	6,594	31.2	87.7
	(%)	7.9%	4.7%	9.7%
Secondary Losses	(kWh)	651	1.6	10.4
	(%)	0.8%	0.4%	1.1%
Dist Xfrmr Load Losses	(kWh)	527	1.3	8.0
	(%)	0.6%	0.3%	0.9%
Dist Xfrmr No-Load Losses	(kWh)	2,176	17.4	17.4
	(%)	2.6%	1.8%	4.3%
Substation Load Losses	(kWh)	306	1.0	4.8
	(%)	0.4%	0.2%	0.5%
Substation No-Load Losses	(kWh)	1,238	9.9	9.9
	(%)	1.5%	1.0%	2.5%
Primary Dist System Losses	(kWh)	1,729	5.5	27.5
	(%)	2.1%	1.4%	2.8%

A simple estimation of realistic long-term loss goals for the Richfield substation area was made by completing the following:

- Re-calculating distribution transformer losses using rated loss values that are consistent with the new Department of Energy (DOE) final rule, 10 CFR Part 431, Subpart K, which requires higher efficiency levels for all new distribution transformers manufactured in or imported into the United States after January 1, 2010.
- Re-calculating primary distribution losses with all existing #4 ACSR and 6A CWC conductors upgraded to 1/0 ACSR.

Fig. 4 graphs the percent losses with the above taken into consideration. This provides a reasonable expectation of where losses may be long-term if the above items are completed over time.

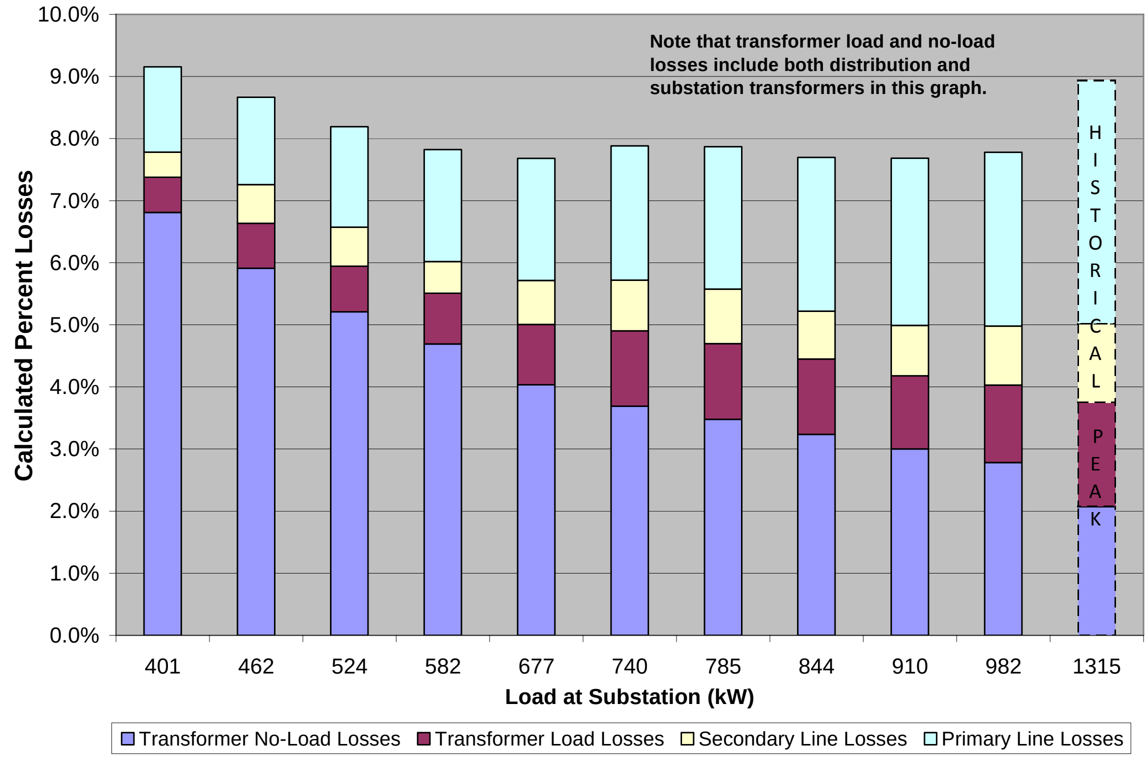

Fig. 3 Richfield substation losses as a percent of purchases

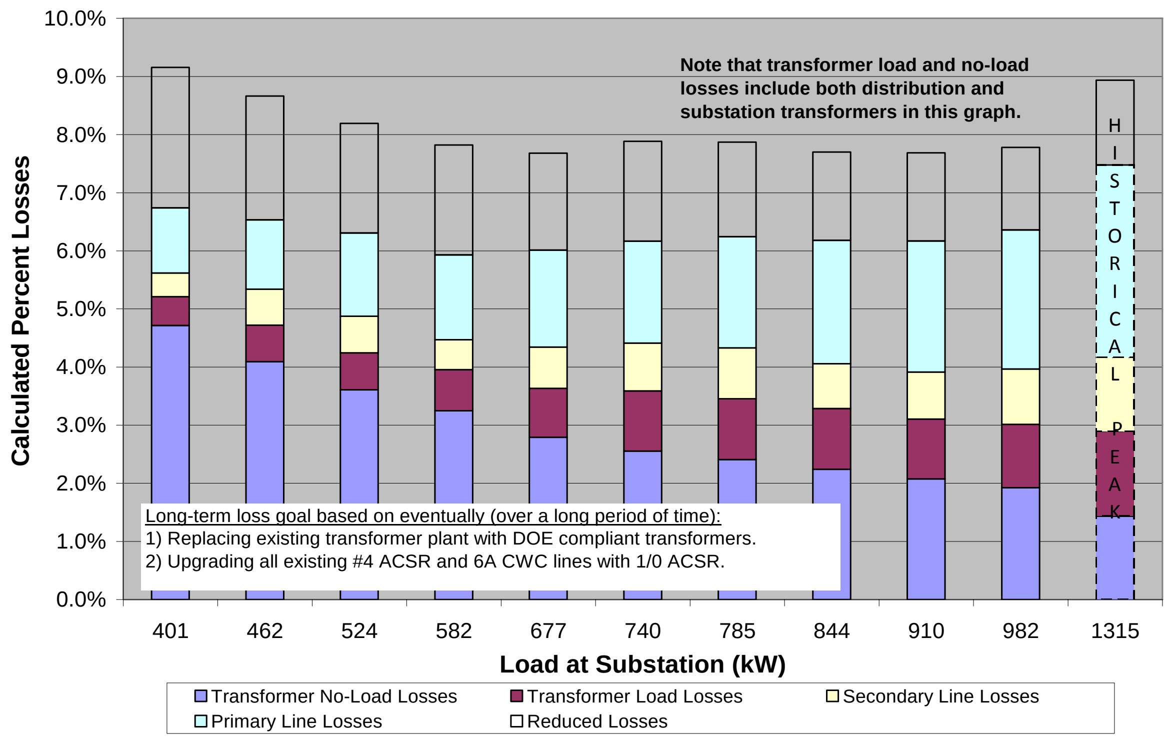

Fig. 4 Richfield substation realistic long-term loss goal

V. CONCLUSIONS

Otsego Electric Cooperative has been successfully calculating monthly losses using data from their AMI system for almost a year. This has resulted in a more accurate representation of total system losses by substation area.

The detailed hourly loss calculation methodology presented in this paper that utilizes data from a deployed AMI and GIS system was successfully applied to a test case area on the Otsego Electric Cooperative system. This evaluation has resulted in much greater insight into the magnitude of losses by system component at various loading levels.

Given all of the challenges associated with collecting hourly interval load data for a large number of meters, collection of this data over an extended period of time may not be practical or even particularly useful. Rather, collecting load data for select system states of interest, from light loading to peak loading conditions, and applying the hourly loss calculation method presented in this paper may be a better approach.

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