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File #: 140056

November 1, 2012

Rosemary Chiavetta, Secretary
Pennsylvania Public Utility Commission
Commonwealth Keystone Building
400 North Street, 2nd Floor North
P.O. Box 3265
Harrisburg, PA 17105-3265

RE: Petition of PPL Electric Utilities Corporation for Approval of its Long-Term Infrastructure Improvement Plan - Docket No. P-2012-2325034

Dear Secretary Chiavetta:

Enclosed are PPL Electric Utilities Corporation's Responses to Data Requests of the Office of Technical Utility Services – Set I in the above-referenced proceeding.

Copies have been provided as indicated on the Certificate of Service.

Respectfully Submitted,

Jessica R. Rogers

JRR/jl
Enclosures
cc: Certificate of Service

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SECRETARY'S BUREAU

S.Gelatko

PPL Electric Utilities Corporation
Response to Data Request of the
Office of Technical Utility Services, Set I
Dated October 15, 2012
Docket No. P-2012-2325034

Q.TUS-P-1. Provide a copy of the Asset Optimization Strategy ("AOS") implemented by PPL Electric as a result of the 2008-2009 assessment and maintenance study of its distribution system. This document was referenced by PPL Electric both in the Petition and the Long-Term Infrastructure Improvement Plan ("LTIIP").

A.TUS-P-1. See TUS-P-1 Attachment 1 – Asset Optimization Strategy.

Condition Assessment, Capital Replacement, and Maintenance Strategy for the PPL Electric Utilities Distribution System

January 30, 2009

Prepared by: Don Platts -MOS Lead
Mark Berner - Distribution
Bob Lally - Substation
Harold Fischer – Protection & Control
Jerry Diehl - Sponsor

Approved by: /s/ Gerald R. Diehl
Senior Director – P&ES

Acknowledgements

In appreciation for the effort put forth by a vast number of individuals throughout PPL EU- the Sponsors, MOS Lead, and sub team leaders would like to acknowledge the efforts of the following individuals whose contributions were key to the success of this project.

Distribution	**Protection & Control**	**Substations**	**Reliability**
Mark Berner	Harold Fisher	Bob Lally	Len Martin
Bob Bobryk	Tom Laganosky	Laura Fredley	Corinne Ronemus
John Trostle	Ken Unger	Curt Chapin	Ed Elwell
Al Molchan	Peter Miles	Dave Neff	Thien Hoang
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Jim Akins	Greg Morton	Tony DePaola	
Jack Cernuska		Scott Beard	
Paul Santarelli		Bob Seier	
		Walt Siroka	
		Ryan Jones	
		Daniel Coulter	
		Randy Vresko	
		Katie Fox	
		Seth Bradigan	
		Don Platts	**Others**
		Mike O'Neill	Chip Wukitsch
		Dave Burdyn	Fred Williams
		Paul Santarelli	Jerry Diehl

We would also like to acknowledge the efforts of the following individuals who participated in various portions of the project or content review.

Distribution	**Protection & Control**	**Substations**	**Reliability**
Mark Berner	Harold Fisher	Bob Lally	Len Martin
Mark Richel	Dave Szatkowski		
Sugi Judd	Mike DeCesaris		
Eric Lysiak	Dave Price		
Bob Seier	Don Reimert		
Tim Figura	Jeff Gilbert		
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Mike Summers			
Joe Jablonski			
Bob Trexler			
Jerry Hope			
Seth Bradigan			
Eric Nederostek			**Others**
Saramma Varghese			Rich Miller

Condition Assessment & Maintenance Strategy for the PPL Electric Utility Distribution System Contents

Condition Assessment & Maintenance Strategy for the PPL Electric Utility Distribution System

Executive Summary

PPL Electric Utilities (PPL Electric) has been funding power system expenditures at the sustenance level for over ten years due mainly to rate caps imposed during deregulation. We have been striving to operate as efficiently as possible; eliminating less consequential work and performing the work we felt was adequate to maintain system integrity and reliability over this period. Performance indicators, such as SAIFI and SAIDI, show we have been successful in our efforts. However, an increasing trend in equipment failures combined with an aging infrastructure indicates that we have reached a point requiring reinvestment in the power system. In addition, the increase in equipment failures is driving an increase in O&M spending that exceeds inflationary influences eroding the ability to target available funds at long term system improvements.

The Maintenance Optimization Strategy (MOS) project was initiated to assess equipment health and generate a strategy for capital replacements and maintenance improvements that would combat these growing concerns. This report provides an assessment of 17 PPL Electric Utilities Distribution asset classes comprising approximately 30,000,000 units of equipment. The assessment includes all distribution lines and equipment, area supply substations and high voltage switching devices. In general, the demarcation point for distribution asset class equipment is the high side switching device on the 69kV or 138kV substation transformer. The report is sectioned into health assessment, capital replacement and maintenance strategy for distribution line, distribution substation and distribution protection & control assets. The health assessment is fundamental to the presented recommendations for capital replacement and optimized maintenance strategies.

A considerable portion of this project was devoted to data collection and development of an equipment health assessment methodology. Due to the lack of sufficient condition data, available data was leveraged and extrapolated to the greatest extent possible. This effort was combined with available age data, field experience and equipment specialty knowledge to create an overall health assessment. This assessment ranked equipment from 1 to 10 in critical health criteria to form a health index for the device. This numbering system was broken into categories explaining the health of the device: Excellent, Very Good, Good, Marginal and Poor.

Based on the team's assessment, 13 of 17 asset classes include equipment rated as "Marginal" or "Poor" (Table ES1), comprising approximately 1.3% of the distribution equipment population. Specifically, 384,420 units have been classified as "Marginal" condition and 256 units have been deemed "Poor". Given the risk to electric service reliability, the team recommends retirement of poorly rated devices in the next 1-3 years and replacement of marginal devices in 3-10 years. Assets determined to be in "Poor" condition include:

- Substation 12kV Interrupting Devices (24 units)
- Protection and Control Electromechanical Relays (183 units)
- Protection and Control Solid State Relays (46 units)
- SCADA Remote Terminals (3 units)

The device level assessments were combined to create an assessment of an Equipment Class and in turn rolled up to assess an entire Asset Class. An example of this equipment aggregation would be an ABB RMAG breaker rolling up to a 12kV Vacuum Breaker Equipment Class and further rolling up to an Asset Class of 12kV Interrupting Devices.

The Asset Class assessments are contained in Table ES1. This table shows that the main equipment concerns on the distribution system from a health and quantity impact standpoint are 12kV interrupting devices, 12kV sectionalizing devices, pole line hardware, conductor and cable, and obsolete electromechanical / first generation microprocessor relays. Specifically, the following items are of concern:

- ITE VBK 12kV Breakers
- *Loadbreak and non-loadbreak porcelain cutouts*
- Porcelain post type insulators
- Anderlite brackets
- Non-porcelain dead-end insulators and porcelain insulators with bails
- 1-3/C PILC 15 kV cable – LTN and substation getaways
- Overhead primary conductor- #6 Cu, #6 CWC, #6A CWC & #7A CWC
- *Reclosing relays and DPU245*

Also note that substation transformers, although a lower quantity in the marginal – poor assessment, represent a large capital replacement cost. In addition, a large quantity of these transformers will be approaching end of life in the next 15-20 years from an age standpoint resulting from a tremendous building surge of the late 1960's to early 1970's. Steps to reduce that wave are built into the capital replacement plan.

Table ES1
Distribution Classification High Level Health Assessment

Distribution Accounting				Asset Health Assessment				
Asset Group	Asset Class	Population	Units	Excellent	Very Good	Good	Marginal	Poor
Distribution	SECTIONALIZING	465,160	Each	231,220	8,061	14	225,865	0
Distribution	POLE LINE HARDWARE	4,823,350	Each	3,148,500	1,426,250	150,000	98,600	0
Distribution	CONDUCTOR AND CABLE	22,486,200	Miles	317,500	21,126,150	986,685	55,865	0
Distribution	TRANSFORMERS - D	453,750	Each	0	453,090	660	0	0
Distribution	POLES AND STRUCTURES	1,199,950	Each	164,210	1,035,330	410	0	0
Distribution	VOLTAGE CONTROL	5,100	Each	0	5,100	0	0	0
Substation	12KV INTERRUPTING DEVICE	1,409	Each	34	315	150	886	24
Substation	138KV INTERRUPTING DEVICE	47	Each	8	39	0	0	0
Substation	69KV INTERRUPTING DEVICE	579	Each	572	0	0	7	0
Substation	DC EQUIPMENT	628	Each	0	31	363	234	0
Substation	MISCELLANEOUS DEVICE	2,593	Each	0	0	2,321	272	0
Substation	SWITCH, HV	5,826	Each	0	5,096	725	5	0
Substation	TRANSFORMER SUB	937	Each	0	73	606	258	0
Prot & Control	ELECTROMECHANICAL RELAYS	25,640	Each	0	11,119	12,842	1,496	183
Prot & Control	MICROPROCESSOR RELAYS	1,006	Each	0	854	35	117	0
Prot & Control	SCADA - REMOTE TERMINAL UNIT	1,345	Each	0	209	431	702	3
Prot & Control	SOLID STATE RELAYS	798	Each	0	480	159	113	46
	Overall	*29,474,318*		3,862,044	24,072,197	1,155,401	384,420	256

The equipment health assessment and associated equipment age study drove the requirements for capital replacement. The capital spending recommendations in this report come from a combination of health assessments and assessments of asset age vs. PPL expected life. To validate end-of-life (EOL) predictions, the team contracted with Kinectrics to provide industry-wide EOL projections for a number of asset classes. This benchmark data is provided in Appendix C.

The resulting capital requirements for the 2010 – 2020 time period, and a comparison with present spending are listed in Table ES2a and ES2b. Combined, these tables define the recommended level of spending to maintain distribution system reliability and begin working towards a life-cycle replacement strategy. The spending is segmented into two tables to call attention to the two different strategies that must be employed to efficiently and economically replace different distribution assets. In some cases, such as distribution substation components, it is more economical to replace distribution assets on an individual component basis. In other cases, such as aging distribution lines, it is more economical to replace all equipment components on a line section or complete line basis.

The spending levels provided in Table ES2a cover the recommended replacements of individual components on the distribution system. The recommended capital *replacements result in an average increase of $65.5 million a year over the 2010-*2020 budgeting timeframe. A majority of these expenditures being applied to replacement of circuit breakers, miles of underground lead cables, line miles of overhead copper primary conductors, overhead equipment or complete rebuilds of overhead distribution circuits.

Table ES2b provides the spending levels to replace aging distribution lines on a line section basis. The Distribution sub team is recommending a program that replaces distribution lines on a per circuit basis where equipment is prone to failure as indicated on the health assessment charts in this report. The methodology used to select the circuits has not been established, but should focus on reducing the risk of the exponential growth of equipment failures moving forward as measured by the reliability indices. (At an estimated cost of $140,000 per circuit or $6,000 per circuit mile, $1.4M capital per year is recommended for the 2010 – 2020 budgets). Details on the replacement plan, criteria, and prioritization methodology are provided in Section 4.1.1.
Note: All of the cost estimates presented in this report are in current year dollars (2008), and were not escalated in the cost projections.

Table ES2a
Recommended 2010 – 2020 Distribution Capital Requirements
(Rounded to nearest $ Millions [2008 $])

Distribution Capital Totals	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	Total
Present Capital	21.6	23.7	23.3	23.6	21.8	21.8	21.7	21.9	22.1	22.3	22.5	246.2
Recommended Capital	86.5	88.0	87.4	89.4	88.0	86.5	87.2	87.3	88.4	89.2	88.5	966.2
Change to Capital	64.9	64.3	64.2	65.8	66.2	64.7	65.5	65.4	66.3	66.9	66.0	720.0

Table ES2b
Recommended 2010 – 2020 Distribution Line Replacement Program
Capital Requirements
(Rounded to nearest $ Millions [2008 $])

Distribution Capital	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	Total $M
Capital Line Replacement	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	15.4

The equipment health assessment was also employed to identify needed changes in PPL maintenance practices. The recommended changes include increases in maintenance task frequency, more robust and focused maintenance tasks and changes to operational based maintenance triggers where operational data is available. A high level expense requirement breakdown to support the recommended maintenance practices is shown in Table ES3. The recommended maintenance improvements result in an average increase of $10 million a year over the 2010-2020 budgeting timeframe. A majority of these expenditures being applied to circuit breaker specific maintenance procedures and preventive inspections, and identification and replacement of known problems on the distribution circuits when the crew is performing other work on the pole or when identified by the appropriate reliability index. Note that the recommended expense spending levels assume a capital replacement program is in place, removing the worst performing components from the system.

Table ES3
2010 – 2020 Distribution Expense Requirements
(Rounded to nearest $ Millions)

Distribution Expense	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	Total $M
Present	18.0	18.2	18.3	18.4	18.6	18.7	18.8	19.0	19.2	19.4	19.5	206.3
Optimized	28.2	28.4	28.6	28.7	28.9	28.7	28.7	28.8	28.9	29.0	29.0	316.0
Change	10.3	10.2	10.3	10.2	10.3	10.0	9.9	9.8	9.7	9.6	9.5	109.8

1 Introduction

1.1 Background

The PPL Electric Utilities (PPL Electric) (PPLE) owns and operates a transmission and distribution system servicing approximately 1.4 million customers in a 10,000 square mile service territory across 29 counties of Pennsylvania. The system consists of more than 39,400 miles of power lines, 300 transmission lines extending 4,950 miles, approximately 1,150 distribution lines extending 34,450 miles, and 377 substations. The T&D asset base in-service is reported at a net value of $4.5 billion.

The PPL Electric Utilities distribution asset base is presently valued at $3.4 billion (FERC Form 1) with a replacement cost valued at $24 billion. Since 2005 PPLE has spent an average of $206 million annually to expand, maintain, and replace distribution system components. In 2008 PPLE decided to undertake a concentrated effort to perform an inventory and condition assessment of distribution assets. The object of this assessment is to develop the basis for an optimized maintenance plan and a performance-based capital replacement program. The goal is to improve system reliability and offset an aging infrastructure while most effectively identifying, controlling, and leveling expenditures. Achieving this goal will result in a system that maintains the reliability standards of PPLE, meets government regulatory and environmental standards, and enhances our ability to safely operate the distribution system.

To achieve the goals of the initiative, The MOS study was segmented by major asset group and four Maintenance Strategy (MOS) sub teams were formed; Transmission, Substation, Distribution and Protection & Control. Each team is comprised of our most experienced power system individuals from throughout the PPLE organization.

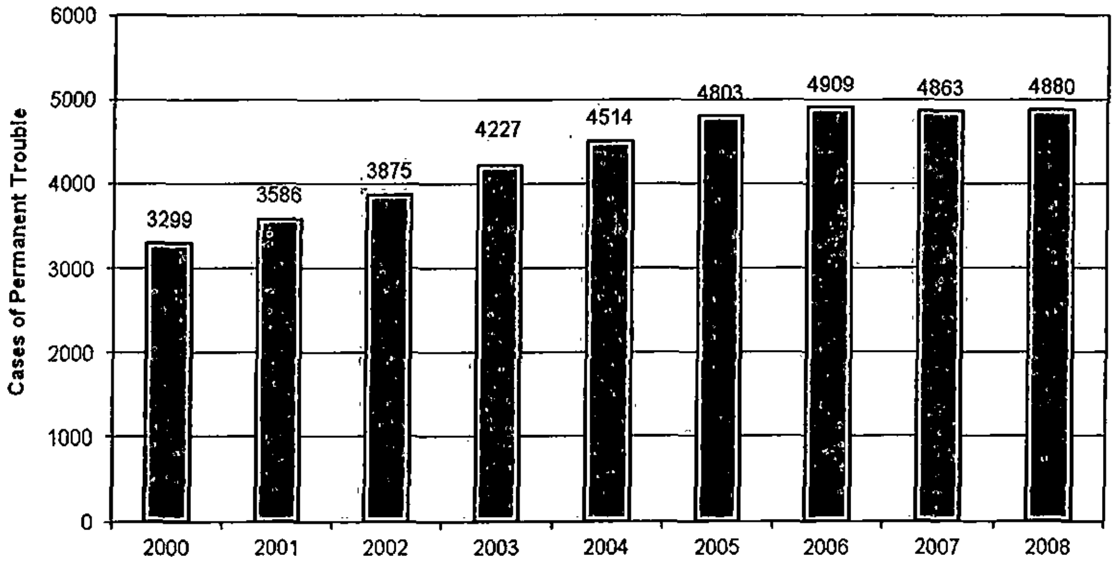
This report contains the work of the Distribution, Substation, and Protection & Control teams associated with all of the T&D assets classified as 'Distribution accounting'. In general, this grouping encompasses equipment operating at voltages up to 69kV, A parallel report, covering assets classified as 'Transmission,' has also been prepared.

1.2 Reliability

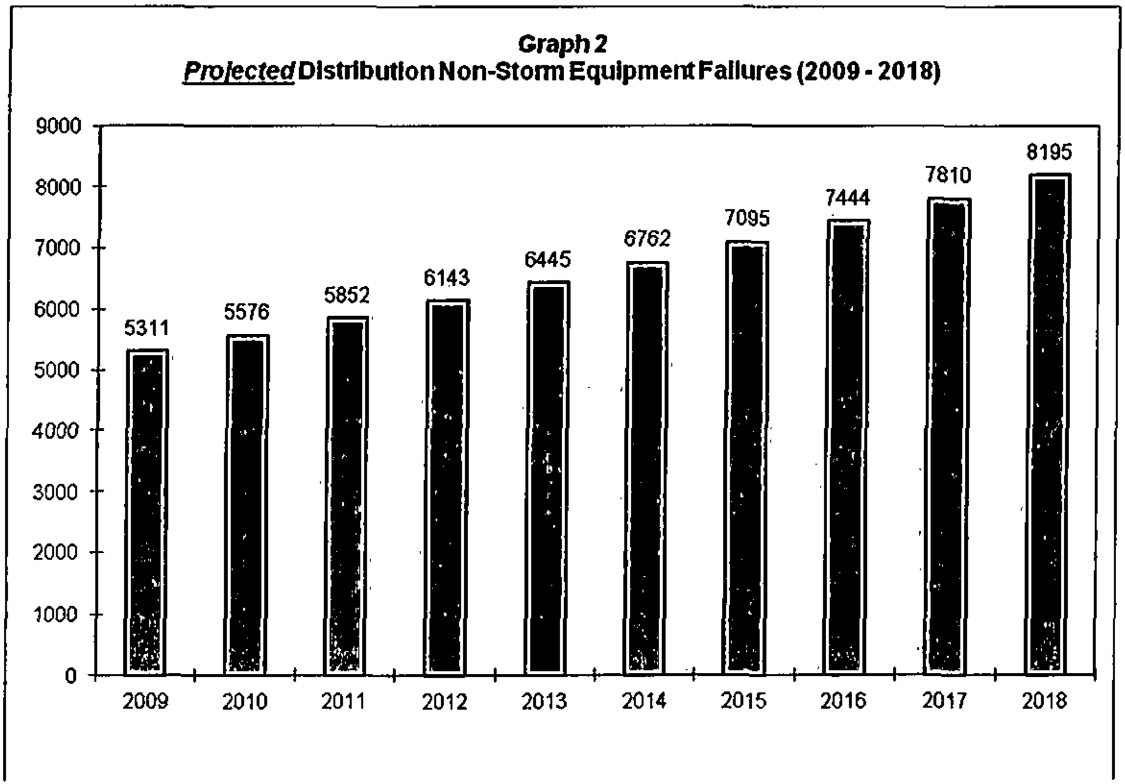
Graph 1 illustrates the historical growth in cases of non-storm[1] distribution equipment failure. Since 2000, the system has experienced a compound annual growth rate in non-storm equipment failure cases of trouble of approximately 5%, with overall growth from 2000 through 2008 reaching nearly 50%. A continuance of this growth rate is not desirable as it will increasingly erode PPL Electric's overall reliability performance, negatively impact customer satisfaction and increase the Company's total cost to respond to these interruptions.

[1] Non-storm historical data is used to reduce year-to-year statistical variability caused by storm activity, thereby more readily identifying potential trends.

Graph 1
Non-Storm Distribution Equipment Failures (2000 - 2008)



Reliability improvement efforts in other key areas, such as vegetation management, have to-date compensated somewhat for the growth of equipment failures in terms of impact on PPL Electric's overall reliability performance; however, if left unmitigated, equipment failures will eventually place the Company at risk of exceeding PA PUC-mandated reliability performance standards. Graph 2 represents a projection of annual non-storm distribution equipment failures from 2009 through 2018 using the historical, approximate 5% compound annual growth rate. Action should be taken to proactively identify, prioritize and begin replacing high-risk distribution infrastructure to help curtail the current equipment failure growth rate and mitigate the risk of experiencing an increased rate of growth in the future.



1.3 Current Maintenance Practices

Presently, PPLE employs a 'time-based' Preventive Maintenance program; consisting of either inspection activities or scheduled maintenance activities. This program, along with an aging distribution infrastructure, is resulting in an increasing amount of corrective maintenance (e.g. equipment repairs). Our present PM program is insufficient in scope and periodicity, inefficient in application across the system, and ineffective in preventing certain failures. A key objective of the MOS study is to specify and improve the maintenance program for each device in order to reduce costly corrective maintenance and drive down overall maintenance costs.

PPLE recognizes the need to migrate to a more effective Performance Focused Maintenance/ Proactive Maintenance (PFM/ PAM) program.

- **Performance Focused Maintenance** requires that activities be designed specifically to meet the maintenance requirements of a particular device and to be applied on a periodicity determined by performance data, testing, and input from knowledgeable maintenance personnel.
- **Proactive Maintenance** requires a programmatic methodology able to extrapolate findings or failures into a fleet solution. This extrapolation goes beyond maintenance improvements and may include a design change, an operational change, or the replacement of a particular asset across the system.

The key to an efficient, reliability-based program is the performance data. This data enables the analysis of device health and identification of trends that form the basis for future maintenance and capital replacement decisions.

For approximately a decade, PPLE has been operating under a rate cap. In that time, we have undertaken several studies to improve efficiency, streamline the workforce, and reduce expenses. The 1995 'Substation Maintenance Standards Report' introduced reliability centered maintenance (RCM), and a reliability analysis database. It reduced the number of maintenance activities and extended the interval between the time base activities based on the analysis of the team –"without sacrificing safety or equipment/system reliability".

Efforts to implement the RCM process were discontinued after a cost benefit analysis that was part of a later initiative. New technology, like the Kelman first trip CB analyzers, was acquired to allow testing in lieu of investigative maintenance procedures. Many of these programs failed to live up to expectations, and have been abandoned.

One of the abandoned tasks was collection of operations, maintenance and failure data for most distribution devices. Consequently, detailed condition assessment, based on existing data, is possible only for substation transformers and circuit breakers. Even in these cases missing data affects the confidence level placed in the results. Appendix C discusses condition data requirements and defines data that must be collected for the major asset classes to drive efficient PFM/ PAM programs. Not all data is critical to asset condition assessment. Appendix C provides a tabular presentation that includes an 'importance' ranking which will drive the prioritization of PPL programs to collect this data.

1.4 Report Overview

The report contains three comprehensive studies of the PPLE distribution system:

- A condition assessment of asset classes,
- A capital replacement program on an asset class basis, and,
- A recommended maintenance plan for each asset class.

The underlying method used to evaluate equipment was the creation of a hierarchy to aggregate and evaluate like components. The lowest level is the 'device level,' the components of which were aggregated into 'equipment classes,' which were then further aggregated into broader 'asset classes' under the three primary asset groups: Distribution, Substation and Protection & Control. An example of the aggregation method employed to perform the analysis is:

Device	ABB RMAG
↪ Equipment Class	↪ Vacuum Circuit Breakers
↪ Asset Class	↪ 12kV Interrupting Devices
↪ Asset Group	↪ Substation

↳ Financial Classification ↳ Distribution

The report is structured to flow from an overview level to a detailed equipment class level as you proceed through the report. The asset group segmentation, distribution, substation and protection & control, is maintained throughout the report. Supporting Device level information, the most specific, is contained in a separate document derived from the Maintenance Optimization Database. Limited portions of the input to the report came from reports prepared by Kinectrics, Inc., a firm versed in asset condition assessment methodologies. They provided two separate reports for PPL, an in-depth study of PPLE circuit breakers (prepared for a separate initiative), and a report on utility industry benchmark data including equipment life spans, condition assessment data requirements, and an approach to investment prioritization.

As previously stated, one of the major challenges facing the MOS teams was the lack of distribution equipment performance data. Except for substation transformers and circuit breakers, the data currently available is limited to asset age, failure logs, or is non-existent. In light of this, the teams used the available data to the extent possible, and then relied on the experience of field maintenance and repair personnel, along with equipment specialists and manufacturer recommendations, to hammer out subjective assessments of each equipment class. These assessments drove the recommended changes to maintenance practices and the recommendations for capital replacements. The assessments also identified data that must be collected to realize the benefits of the postulated PFM/PAM program, predictable reliability, controlled and predictable maintenance costs, and rational performance-based capital investments.

Using the available data to its fullest; drawing on industry experience; researching manufacturer recommendations; and calling on the most experienced PPLE personnel; the MOS teams have developed the best analysis of the transmission system health in thirty years. Many shortcomings in maintenance programs and equipment replacement have been identified and course corrections weaved into the MOS effort will benefit PPLE going forward. Still, this is only one step toward PFM/PAM. The next step will be to begin to collect equipment performance data while applying revised maintenance practices. It is recommended that in two years, a study similar to this one be rerun with actual performance data to verify assumptions, better assess maintenance and replacement criteria, and correct the programs where necessary.

1.5 Objective

The objective of this study was to conduct an equipment condition assessment of the distribution system, to drive recommendations on capital replacement and maintenance program strategies.

In accomplishing this objective, the MOS study was to support the following:

- Capital (MSR) and expense recommendations for the 2010-2020 budgets

- Justifications for financial requirements presented to the Pennsylvania Public Utility Commission
- Development of a new, well planned, and efficient MSR capital replacement program to arrest infrastructure deterioration.
- Maintaining or improving equipment availability, reliability, and lifespan to support PPLE business needs
- Controlled maintenance costs

1.6 Scope

The scope of work included in the distribution MOS study:

- Determination of available data for each equipment class
- Definition of information needed to assess asset health
- Identification of additional data needed to support PFM/PAM
- Definition and weighting of condition indicators for the health index of each equipment class
- Assessing the equipment condition
- Developing a capital replacement strategy and proposed programs
- Identifying areas in the maintenance program that can be improved to support reliability and equipment operation
- Creation and population of an MOS database that contains inventory data (where available), health assessment, capital replacement strategies, financial and reliability impacts on a device group basis.

The Distribution asset classes evaluated by this study:

Asset Group	Asset Class
Distribution	Conductor And Cable
Distribution	Pole Line Hardware
Distribution	Poles And Structures
Distribution	Sectionalizing
Distribution	Transformers
Distribution	Voltage Control
Substation	69kv Interrupting Device
Substation	138kv Interrupting Device
Substation	DC Equipment
Substation	Miscellaneous Device
Substation	Switch, HV
Substation	Transformer
Substation	12kv Interrupting Device
Protection & Control	Electromechanical
Protection & Control	Microprocessor
Protection & Control	SCADA - Remote Terminal Unit
Protection & Control	Solid State

The scope of work associated with asset health assessment, but outside of the boundaries of this report includes:

- Prioritization of replacements within an equipment class
- Inventory of facilities that have no inventory data
- Creation of a strategy for obtaining operational data for condition assessment. Determining the optimum repository for housing the data. Integrating plans and staffing to ensure successful implementation of the program to support condition assessment and PFM/ PAM.

1.7 PA PUC Inspection & Maintenance Standards

The PA PUC is required to monitor the reliability performance of PA electric distribution companies (EDCs). In 2008, the PA PUC adopted final form regulations designed to improve reliability performance for the EDCs by requiring them to file biennial inspection and maintenance plans, as well as adhere to prescribed standards.

To accomplish this task for PPL, a team will be formed during the 3rd quarter of 2009 to develop the strategy associated with biennial plan filings for the mandated inspection and maintenance activities. Given the timing of this activity, the MOS teams did not specifically incorporate the PA PUC inspection and maintenance standards in their respective analyses. It is anticipated that MOS team members will be contributors to the development of PPL Electric's biennial inspection and maintenance plans, thereby ensuring continuity between these two efforts. Additional details are provided in Appendix E.

1.8 MOS Database

The data developed to support the preparation of this report resides in an extensive database. It was originally developed to document the PPLE maintenance program for the various equipment device groups. The MOS team found that is could easily be adapted to serve as the repository for the information required to establish recommended maintenance program enhancements, and to do a high level condition assessment. Later, cost data was added to allow development of the capital replacement program. In addition, data for predicting the change in annual failures as a result of the proposed activities was added. Then a table was developed to calculate the predicted effect on SAIFI over the 2010 to 2020 time span.

This database became the primary tool used by the sub teams as they gathered data and developed the evaluation information. Most of the time devoted by team members was spent developing this database. The charts produced for this project were developed from MOS database reports and queries.

2 Recommendations

High level recommendations are provided in the subsections below; segment by distribution line, substation, protection and control and T&D system condition assessment. More detailed recommendations and their basis are provided throughout the report. More specific device level capital and maintenance recommendations are provided as part of each entry in the MOS Database and by be viewed in the separate compilation report of database equipment reports.

2.1 Distribution Lines

2.1.1 Capital

- Continue capital replacement of distribution line components as part of the maintenance and repair of existing lines.
- Develop a formal visual inspection program for the distribution system. This should be completed with a high level of accuracy and good record keeping. It will support capital replacements by creating a detailed inventory and maintenance by identifying the locations of equipment that is prone to trouble. Portions of the cost may need to be allocated as expense.
    - Additional resources are required, and are recommended to be added to the current attachment group to complete the field surveys. To complete the program on a three year cycle, we estimate the project will require the addition of 27 properly trained inspectors. If the inspection cycle is extended to five years, 16 properly trained inspectors would be required. The cost per inspector, per day, with all financial adders is $650 per day or $163,000 per year. This equates to $2.6 to $4.4 MM each year of the inspection program, approximately $13 MM for the inspection and inventory.
    - Develop a data base to capture field data supplied information via handheld units. $100,000.
- Develop a capital replacement program that replaces distribution lines on a per circuit basis where equipment is prone to failure as indicated on the health assessment charts in this report. The methodology used to select the circuits has not been established, but should focus on reducing the risk of the exponential growth of equipment failures moving forward as measured by the reliability indices. The team recommends replacing 100 circuits per year so that the expected 1000 circuits may be completed in the 2010 – 2020 time span. ($140,000 per circuit or $6,000 per circuit mile = $1.4M capital per year for the next ten years)
- Replace 35 miles per year of Copperweld and Copperweld Copper conductor across the system). Estimated capital cost is $250,000/mile and expense is $30,000/mile (2008 dollars). Given this rate, we will replace all of the conductor on circuits with the highest historical contributions to Customers with Multiple Interruptions (CMI) and will improve the circuit health and resultant reliability performance throughout the next 20 years.

- Replace the existing 25 miles of 1-3/c 15 kV paper insulated lead cable (PILC) underground cable. (5 miles per year, $2.5M capital and $150,000 associated expense per year over the next five years).
- Repair/rebuild an additional six manholes and vaults with known structural concerns that were identified during routine inspections. (Current funding provides for six locations per year of the estimated 120 total. The additional six locations require an additional $900,000 capital and $440,000 associated expense per year).
- Replace the existing 10 miles of 600 V lead secondary cables in the low tension networks (Two miles per year for the next five years, $200,000 capital and $40,000 associated expense per year).
- Replace submersible transformers and network protectors in corrosive environments that have reached their expected life (book life). (Additional funding projected starting in 2015, $550,000 capital and $170,000 associated expense per year)
- Overhaul Oil Circuit Reclosers (OCRs), Vacuum Circuit Reclosers (VCRs) and Sectionalizers on an eight year cycle rather than ten. (An additional $204,000 capital and $21,000 associated expense per year).

2.1.2 Expense

- Develop a formal visual inspection program for the distribution system. This should be completed with a high level of accuracy and good record keeping. See the explanation above capital recommendations for the details. Portions of the cost may need to be allocated between capital and expense.
- Replace equipment that is prone to failure (as indicated on the health assessment charts in this report) while completing other work on a pole or at an underground location. Replacing these items, while at the job location, over the next ten years should reduce the risk of exponential growth of outages and the associated deterioration of the reliability indices ($550 per pole average cost, 4090 poles/ year, results in $2.25M per year for the next ten years)
- Overhaul LTN transformers with a high voltage switch and XLP terminations on a 12 year cycle. ($100,000 per year).

2.2 Substations

2.2.1 Capital

- Establish, and continuously fund, a new program to replace (8) aging 69-12kv self- or forced-cooled power transformers annually over the next 10 years. This equipment group has several units significantly beyond expected lifetime which are exhibiting signs of advanced deterioration and need to be replaced. In addition, robust system development from the '60s and '70s has created a "wave" of units all having similar age grouping. This wave will approach end of expected useful lifetime by 2025; annual funding should be significantly increased by that timeframe to match that volume.

- Continue to annually fund an existing program to replace problematic 12kv circuit breakers over the next 10 years based on a combination of advanced age, chronic mechanism operational issues and lack of available, suitable, spare parts. Although the program initially started with a planned scope of approximately 12 CBs per year, a more robust scope of (30) thirty CBs per year minimum over the next 10 years will be necessary to match the volume of aging, deteriorating equipment.
  Though initially targeting three specific CB vendor/ types, expand the scope to include all of the following (_) denotes system quantity in-service:

  (2) Roller Smith type OC oil CBs
  (1) GE type FHKO oil CB
  (294) GE type FKD oil CBs
  (18) GE type FK oil CBs
  (23) Allis Chalmers type OZ oil CBs
  (5) Allis Chalmers type FZO oil CBs
  (3) Federal Pacific type AF oil CBs
  (8) Federal Pacific type JCE oil CBs
  (2) Westinghouse type G oil CBs
  (44) Westinghouse type GC oil CBs
  (17) Westinghouse type GO oil CBs
  (34) McGraw Edison type VAC vacuum CBs
  (92) ITE type VBK vacuum CBs
  (245) GE type VIB vacuum CBs
  (2) Allis Chalmers type MC air CBs
  (35) GE type AM air CBs
  (16) McGraw Edison type WSA air CBs

- Replace all (7) vintage 69kv circuit switchers within the next 5 years. These vintage devices no longer have vendor technical support or field services and replacement parts are difficult to obtain.
- Replace all (5) vintage propellant-type high speed ground switches with spring-actuated equivalents within the next 5 years. Propellant type devices have experienced long-term mechanism problems due to residue accumulation and subsequent corrosion following normal operation and periodic functional testing.
- Establish, and continuously fund annually, a new program to replace 48VDC battery chargers over the next 10 years due to high average age, ongoing operational problems, lack of spare parts or high cost of spare parts relative to cost of a complete replacement unit. Scope would include approximately (20) chargers/year for the first 4 years to address the wave of those units already exceeding or fast approaching design lifetime. Thereafter, fund at about (4) chargers/year for the balance of the period.
- Establish, and continuously fund annually, a new program over the next 10 years to replace in kind substation 12kv solid dielectric cables (transformer leads and bus section connections only) Existing cables have a high average age approaching design life and increasing level of Doble testing and in-

service failures. Funding levels should allow for disposition of (12) 12kv 3-phase circuits per year over the 10 year timeframe. Or alternatively, initiate projects to change the substation design to facilitate overhead, air-insulated connections where possible.

2.2.2 Expense

The primary recommendations are:

- Increase the frequency of Doble testing and oil dielectric testing of power transformers from 8 years to 4 years. More frequent data collection will improve the engineering condition assessment accuracy and help to earlier identify the need for subsequent condition-based maintenance.
- Eliminate annual 12kv circuit breaker trip testing activities system wide. This procedure has proven to be of marginal value considering the CBs generally cycle periodically in response to system events as well as being switched in/out for scheduled device maintenance and relay testing.
- Establish new 4-year clean/adjust/lubrication work procedures specifically tailored to the particular 12kv breaker manufacturer/style. This work would focus on the key lubrication points inherent to that particular device's operating mechanism design and provide a more thorough process to improve correct breaker operation statistics. The costs are partially offset by elimination of the annual trip testing. Procedures would be prepared for approximately (24) different breaker styles and scheduled in the second year of the modified 4-year service cycle (see next item).
- Increase the frequency for the service procedure on select group of 12kv breakers (about 24) from 8 years to 4 years and increase the associated manhours to provide more robust maintenance. These changes are recommended based on historical experience with the operation of these devices, known failure modes and the magnitude of effort necessary to address the individual failure modes.
- Increase the frequency of Doble and Hi-pot OCB (oil circuit breaker) testing from 8-year cycle to 4-years. Again, more frequent data collection will improve the engineering condition assessment accuracy and help to earlier identify the need for subsequent condition-based maintenance.
- Improved and expanded overhaul of propellant-type high speed ground switches to address internal corrosion issues. This expense will ultimately cease once all devices have been replaced as part of the capital replacement program however, action is needed in the short term to ensure reliable operation when required.
- Establish a special 4-year Doble testing activity specifically for GE type U bushings mounted on 69-12kv power transformers. More frequent testing will provide additional data to assess changing characteristics and provide opportunity to detect declining performance and replace before in-service failure.
- Increase the frequency of power fuse inspection (flow testing) from 8 years to 4 years. This action is recommended based on a historical observations of failure to operate correctly due to a manufacturer design deficiency.

- Increase the frequency of Doble testing of 12kv power cables from 8 years to 4 years. More frequent data collection will improve the engineering condition assessment accuracy and help prioritize cable replacement in the capital program.
- Increase the frequency of Doble testing of 69 and 138kv surge arresters from 8 years to 4 years. More frequent testing will provide additional data to assess changing characteristics and provide opportunity to detect declining performance and replace before in-service failure.

2.3 Protection and Control

2.3.1 Capital

- Replace aging and obsolete electromechanical relays, such as Westinghouse type CO, General Electric type IAC, and associated reclosing relays with ABB DPU-2000R microprocessor relays for 12kV feeder protection. This will ensure that the assets do not exceed their life expectancy, operate in a secure and reliable manner, provide added-value such as event recording and self-diagnostics, and increase the maintainability of the asset by significantly reducing the number of components and wiring terminations.

- Replace first-generation ABB DPU-245/445 microprocessor relays with ABB DPU-2000R microprocessor relays due to reliability issues and the lack of complete self-diagnostic capability.

- To ensure continued performance with regard to the Supervisory Control and Data Acquisition (SCADA) system, legacy SCADA remotes, such as the Harris, Ferranti, and the Conitel systems, should be replaced with modern PLC-based SCADA systems.

2.3.2 Expense

- Decrease the periodic test intervals for problematic electromechanical relays. The team recommends changing the test interval from eight (8) years to four (4) years for certain electromechanical protection, reclosing, and auxiliary relays. These relays are included as part of the capital replacement strategy.

- Develop automated test plans to streamline acceptance, installation, and periodic testing of complex electromechanical and microprocessor-based relay schemes. This investment will have long-term benefits, including the development of standardized test methods that save testing time, provide consistent results, and generate electronic records which are readily available for regulatory review. Corollary benefits of automated test plans and electronic records include making it easier for regional test crews to share test plans and "best practices" for testing; providing opportunities to update, standardize, and centrally store an extensive library of test procedures.

- Evaluate and implement new capabilities within modern protection and control equipment. For instance, modern relays can predict maintenance activities by trending items such as circuit breaker operating times, trip coil current, and temperatures. In addition, new relay technology can determine the fault type, location, and incipient cable insulation failures.

2.4 T&D System Condition assessment

- Begin data collection to support ongoing condition assessment of T&D assets at the individual device (Serial Number) level.
- Form a Data Collection Team to implement this program. Staffing to be determined; expected to be part time.
- Utilize the condition assessment 'Health index' features of Cascade to establish performance based maintenance triggers.
- Institute a Capital Replacement Prioritization Team to develop the prioritization methodology, and the identification and implementation plans.
- Develop interfaces with the MOM system, or institute paper forms and clerical procedures to get maintenance and equipment failure data into Cascade.
- Develop the Cascade procedures for the testing and inspections to obtain the "very important" data defined in the tables of Appendix C., Supplement with the requirements established by PPL equipment specialists. Establish test/ inspection frequencies.
- Inventory distribution line assets and update EFD.
- Use the updated data in CASCADE to populate missing fields in EFD as it is the primary data repository for system inventory data.

3 Condition Assessment

The objective of this portion of the project was to conduct an equipment condition assessment for the assets of the T&D system - within the limitations of schedule defined by the PPLE budget cycle for 2010. The equipment condition assessment was designed to quantify the extent of degradation. The result of this assessment has been used in conjunction with the age profile (or other factors) to provide a recommendation for the initiation of a capital replacement program. Groups of devices that meet the replacement criteria within the 2010 to 2020 time frame have been identified.

PPLE performed these condition assessments at a high level. For example: 69 kV power transformers; 12 kV underground jacketed cable; fir – wood distribution poles; etc. As a result, the health index values produced represent the judgment of the team as to the average condition of the equipment on the PPLE system for each device classification. It considered the equipment age; failure rate; obsolescence; difficulty and frequency of maintenance; safety exposure; operating environment; and possibly other factors.

3.1 Condition Assessment Methodology

The condition assessment (i.e. Health Index) was based on evaluations at the device level within the following hierarchy:

Asset Class Level
↳Equipment Class Level
↳Device Level
↳*Serial Number Level*

The condition assessment was performed at the device level and summarized up to the Asset Class level. For this study, no evaluations were done at the level of a particular component (the serial number level).

The condition assessment methodology for each distribution equipment device group can be summarized by:

Developing evaluation criteria (condition indicators)
Weighting the importance of the criteria
Rating the equipment
Calculating the weighted Health Index

The following seven criteria (condition indicators) were established by the maintenance optimization team members as providing a consistent and practical basis for assessing the condition of the distribution components. These particular definitions were established by the team for use in the MOS condition assessments.

- **Maintainability** – Cumulative affect of required preventative maintenance, corrective maintenance and repair on the device's in-service availability and *amount of work required to sustain acceptable operational performance.*

- **Supportability** – The ability to maintain, repair and return equipment to service in a timely manner. This includes but not limited to availability of an in-kind replacement, spare parts, vendor support, engineering technical expertise, adequately trained maintenance personnel and equipment redundancy.

- **Safety** – the ability for the equipment to operate with minimal risk of danger or injury to the worker or general public. [The ability of the device to operate in a risk-free environment.]

- **Age** – estimated average age of the in-service age and age distribution of the equipment class. While age profiling provides some useful guidance, it has been recognized that not all older assets are necessarily in poor condition and not all newer assets are immune from degradation and failure.

- **Failure Rate** – the estimated frequency (average number of failures per year) at which a component or system fails to operate as designed or specified.

- **Resources** – An evaluation of components that require excessive skilled labor to maintain.

- **Environment** – devices may contain materials or fluids that could present *hazards to society (lead, asbestos, PCB, SF6, etc.) or physical considerations* that could affect component operation due to moisture, vibration, dust, heat, etc.]

Each sub team had the freedom to establish which of the criteria from the list would be used in the evaluation of the assets under their control and the weighting it should receive.

Weighting factors used in the condition assessment methodology recognize that some condition indicators affect the health index to a greater or lesser degree than other indicators. These weighting factors were arrived at by consensus among various members of the team who have years of extensive distribution system equipment maintenance and design experience

General Methodology Details

The general methodology used by each sub team is described below. Section 3.2, 3.3, and 3.4 describe the specific procedures for each team when it utilized variations or alternative *approaches.*

The specific methodology utilized for the condition assessment of the distribution equipment consists of 4 steps.

1) PPL's equipment specialists and team members established a list of 4 to 7 criteria (condition indicators) for each of the device level groups. Each sub team

reviewed the criteria list above and chose the criteria that would be applicable to the particular equipment device group under evaluation.

2) They evaluated the significance that each criteria is believed to contribute to the overall condition assessment. Then each of the criteria was weighted in 5% increments on a scale from 0% to 100%. To normalize the results, the sum of all of the criteria weightings was required to be 100%.

3) *The equipment was reviewed, discussed, and a rating was developed on a scale from* 0 to 10, with 10 being the considered excellent and 0 being very poor or subject to imminent failure.

4) The database includes a calculation routine to produce the weighted Health Index. Each criteria weighting % and rating factor were multiplied together and then totaled to calculate an overall weighted rating. The overall sum divided by 100% produces the normalized individual Distribution Health Index, on a scale of 0 to 10.

Some of the distribution and substation database entries have no Condition Assessment, because they are not T&D devices. For these relatively few items a condition assessment rating was not appropriate, or possible, and therefore, that methodology was not used. For example, documentation on foot patrols and substation inspections was included in the report. These are important maintenance activities that must continue to be planned, budgeted, and executed. The work scopes of these activities are reviewed and appear in the maintenance section.

3.2 Distribution Lines

The condition assessment methodology used for the distribution equipment was similar to the general method described above. The weighting factors used for the health index were developed during numerous meetings and discussions that reached consensus among Distribution Maintenance, Distribution Operations, T&D Design, System Reliability and Work Scope, and Systems Shops personnel.

The following four (4) condition indicators are generally regarded by the distribution maintenance optimization team members as providing a consistent and practical basis for assessing condition of the distribution components. The weighting applied to them varied from one device to another, as deemed appropriate.

- Failure Rate
- Age
- Safety
- Environment

The distribution condition ratings are mainly subjective. Since most of the distribution equipment is considered to be mass property, we had little or no data on the failure rate or age of the installed equipment to develop our analysis. As a result, the condition indicators relied mostly on input from engineering experts and experienced field personnel. Some data did exist for poles, underground direct buried cables, and low tension network equipment. This data was included in the analysis. In addition, data was available from the Electric Facilities Database (EFD), and System Shops repair records. This data was used to determine quantities for the major property items and calculated quantities for minor property items. However, the condition assessment for the distribution equipment was heavily based on knowledge from the experts on the team and engineering judgment.

3.3 Substation

The condition assessment methodology for substation equipment was developed using the following condition criteria with percent weighting as noted for every equipment device group:

- Failure Rate (15%)
- Safety (10%)
- Age (50%)
- Supportability (15%)
- Maintainability (10%)

Among the list of available criteria to choose from, these are generally regarded as providing a sound basis for the physical/electrical equipment found in high voltage substations and switchyards. Weighting percentages for each are shown in parenthesis and are fixed over all device classes. Each of the criteria is given a specific rating (scale 0 [poor] to 10 [excellent]) based on collective input and consensus of a cross-functional team of design/maintenance/test personnel and engineers having considerable experience with the installation, operation and maintenance of the equipment.

Ratings applied to all except "Age" are largely based on subjective opinions of the experts with consideration of their knowledge of operating history, failure mechanisms, failure frequency and maintenance issues. In many instances, information available from periodic inspection sheets, substation trouble report database, test reports and reliability consultants, though only qualitative in nature, validates the engineering judgments.

"Age" ratings were derived by directly prorating the average of the device class as compared with the PPL expected lifespan of the equipment. Where average age is equal to or greater than PPL expected life, the assigned rating is zero. Average age data calculated from specific device year of manufacture data obtained in Cascade.

3.4 Protection and Control

The process of determining the condition ratings for protection and control equipment is somewhat subjective. Although we had adequate data with regard to age, failure rate, and supportability, the other condition indicators relied mostly on engineering experts. With regard to age, failure rate, and supportability, the data was derived from the Cascade database, the spare relay inventory database, and manufacturer information. The data sources are only as accurate as information that was gathered over the years and entered in Cascade and relay inventory databases. The Cascade and relay inventory databases are continuously being updated by protection and control personnel as part of installation, testing, and maintenance.

Based on their many years of field experience, the protection and control team determined how resources, maintainability, and environmental impacts would affect the condition a particular protection and control asset. These ratings were more subjective, and thus the weighting factors used for these condition indicators were adjusted accordingly.

The condition indicators were initially evaluated using data from periodic inspections, maintenance test reports, measurements and engineering judgment. The compilation of this data was performed by protection and control personnel as a part of routine maintenance activities. In some cases, data may be missing, out-of-date, or of questionable integrity. Each of these situations could affect the accuracy or validity of the associated health index. As done in each of the teams, devices of similar function and style were grouped together for simplification. For instance, most auxiliary relays were grouped together. However, the auxiliary relays were separated if the condition assessment, maintenance philosophy, or capital replacement strategy was different from other components within the same equipment class.

Approximately 80% of the Relay Health Index numbers are based on data.

3.5 Requirements

Assessing asset condition requires an understanding of the degradation or deterioration process of the equipment in the equipment classes. The failure modes of the equipment in the selected asset classes and the consequence of failures are best evaluated at the individual device (serial number) level. In the future we expect that the necessary performance data will be available to support an evaluation to this level.

Going forward, we recommend a more refined assessment to identify specific components that are critical to the operation of the system and then perform a detailed condition assessment on each of these components. (In this project, that approach is referred to as the 'serial number level' of analysis). An example of how this would be done is laid out in Appendix D. In Appendix C of this report, each equipment class is discussed, and tables are presented detailing the data, test results, and inspection requirements necessary to perform a detailed condition assessment. PPL should supplement the Kinectrics lists with the requirements established by PPL equipment specialists. The team recommends that PPLE invests the resources and IT assets to collect, store, and analyze this data so that future condition assessments may be performed in detail for individual components.

3.5.1 Requirements for additional data to be used in future detailed studies

PPL has limited information on many of the devices installed on a particular transmission structure. As a result, we don't know the manufacturer, model, rating, or age of the device. In some cases this information can be deduced from inspections, or knowledge of the date of construction, etc. In order to ensure an accurate, detailed condition assessment in the future, the team recommends a program to gather that data, either from field surveys, tracking of equipment identification data during installation, or a combination of the two. After identifying the devices, PPLE will also need to develop a method for tracking problems and failures of these devices.

In general PPL will need:

- A detailed, field verified Inventory
- *Sufficient maintenance records to support condition trending*
- Device/ component test results / summaries
- Inspection Reports: routine and specific for condition assessment
- Failure reports with root cause

Additional detail for specific asset classes is reviewed and evaluated in Appendix C.

PPLE must retain, enhance and provide links between the existing systems, Cascade, Prides, TMP-, TOA (Trnsf DGA/ Oil tests), Doble Office, and others.

The projected cost for all of the programs suggested is $XXXXX

3.5.2 Detailed Equipment Descriptions – Not Included in Report

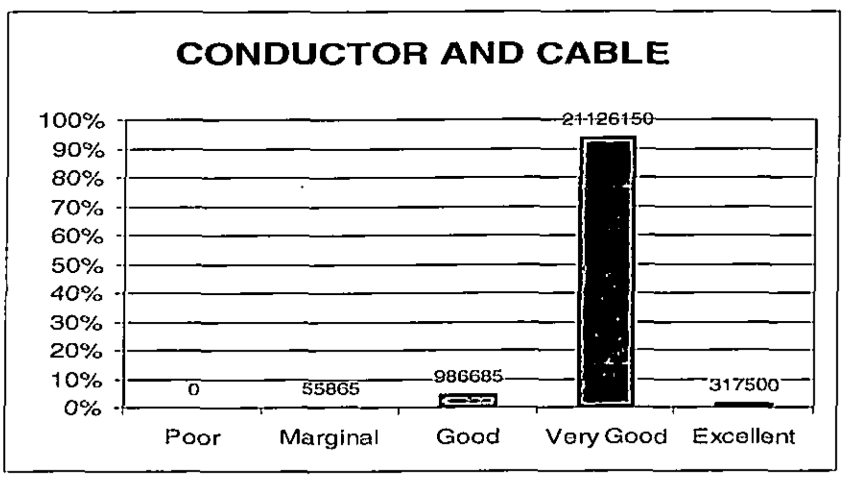
Detailed Equipment condition assessment studies performed by outside contractors will normally include one or more pages of background information describing each component of the equipment in the study. This is intended as educational material *for decision makers who have little experience with the equipment. This is normally a* review of the basic operation, design, construction, and auxiliary devices of the device. Then it describes the primary maintenance problems, failure modes, and the long term degradation processes of the components and auxiliary devices. While PPL equipment specialists could provide this type of information, the MOS team believes that this is tutorial in nature and does not provide additional insight into the condition of the devices, or support capital replacement or maintenance strategies. Specific topics that are pertinent to the proposed changes in our programs are reviewed briefly.

3.6 Health Ratings

Health Index Ratings by Asset Class:

Distribution Accounting				Asset Health Assessment				
Asset Group	Asset Class	Population	Units	Excellent	Very Good	Good	Marginal	Poor
Distribution	*SECTIONALIZING*	465,160	*Each*	231,220	8,061	14	225,865	0
Distribution	POLE LINE HARDWARE	4,823,350	Each	3,148,500	1,426,250	150,000	. 98,600	0
Distribution	CONDUCTOR AND CABLE	22,486,200	Miles	317,500	21,126,150	986,685	55,865	0
Distribution	TRANSFORMERS - D	453,750	Each	0	453,090	660	0	0
Distribution	POLES AND STRUCTURES	1,199,950	Each	164,210	1,035,330	410	0	0
Distribution	VOLTAGE CONTROL	5,100	Each	0	5,100	0	0	0
Substation	12KV INTERRUPTING DEVICE	1,409	Each	34	315	150	886	24
Substation	138KV INTERRUPTING DEVICE	47	Each	8	39	0	0	0
Substation	69KV INTERRUPTING DEVICE	579	Each	572	0	0	7	0
Substation	DC EQUIPMENT	628	Each	0	31	363	234	0
Substation	MISCELLANEOUS DEVICE	2,593	Each	0	0	2,321	272	0
Substation	SWITCH, HV	5,826	Each	0	5,096	725	5	0
Substation	TRANSFORMER SUB	937	Each	0	73	606	258	0
Prot & Control	ELECTROMECHANICAL RELAYS	25,640	Each	0	11,119	12,842	1,496	183
Prot & Control	MICROPROCESSOR RELAYS	1,006	Each	0	854	35	117	0
Prot & Control	*SCADA - REMOTE TERMINAL UNIT*	*1,345*	*Each*	*0*	*209*	*431*	*702*	*3*
Prot & Control	SOLID STATE RELAYS	798	Each	0	480	159	113	46
	Overall	*29,474,318*		3,862,044	24,072,197	1,155,401	384,420	256

3.6.1 Distribution Lines

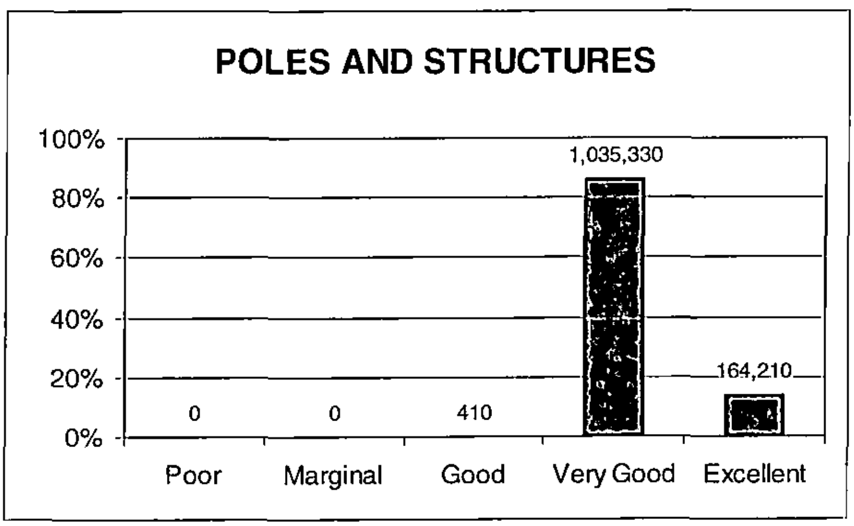


<u>Distribution Conductor and Cable</u>

- The Conductor and Cable asset class consists of 4 equipment classes. Health Index Ratings for the asset class ranged from poor to excellent.
- Within the Connector equipment class 50,200 devices are rated marginal, 190,000 are rated good; 20,540,000 are rated very good, and 312,000 are rated excellent.
- Within the Conductor equipment class 3,500 miles are rated poor, 450 are rated marginal, 4,300 are rated good, and 39,700 are rated excellent.

- Within the Primary Cable equipment class 1,025 miles are rated marginal, 2,800 are rated good, and 571,140 are rated very good.
- Within the Secondary Cable equipment class 10 miles are rated marginal, 400,385 are rated good, 375,000 are rated very good, and 210 are rated excellent.
- The average rating of the asset class is very good.

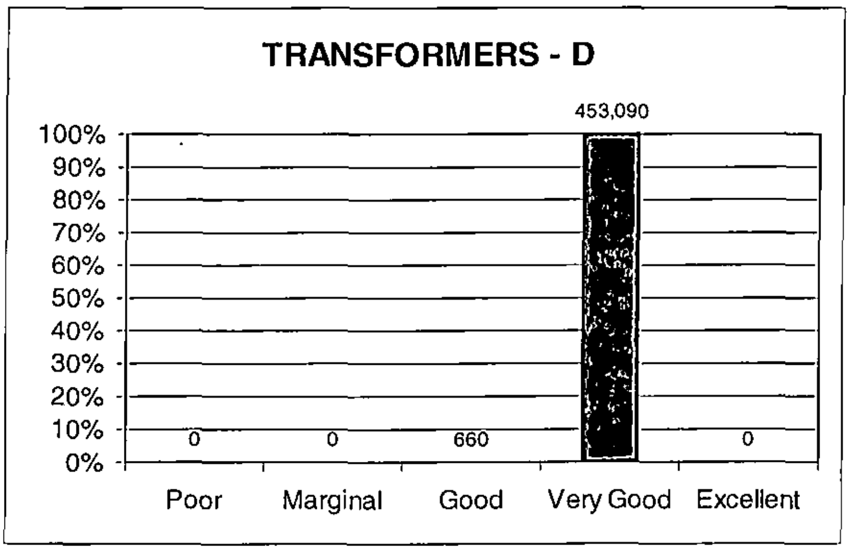
  - The conductors rated poor or marginal are:
    - 250 miles of Al or ACSR XLP overhead conductor without Arc Protective Devices (APDs) installed
    - 3,500 miles of #6 Solid Cu , #6 Solid Cu Weld –CW and , #6A and #7A Cu Weld Cu -CWC overhead primary conductor
    - 200 miles of open wire secondary or service conductor of various sizes and types
    - The connectors for primary overhead conductor rated marginal are:
      - 50,000 bolted connectors
      - 180 Bridges disconnect switches
  - The primary cables rated marginal are:
    - 25 miles of 1-3/C Cu PILC 15 kV cables installed in the low tension network or as substation getaways.
    - 1.000 miles 1/C Al 15 kV un-jacketed underground distribution cable
  - The 10 miles of 600 V Cu, lead covered secondary cable installed in the low tension networks was rated marginal



Distribution Poles and Structures

The Poles and Structures asset class consists of 5 equipment classes. Health Index Ratings for the asset class ranged from good to excellent.

- Within the PMH Switchgear equipment class 1,000 devices are rated excellent.
- Within the UG Vaults equipment class 6,000 devices are rated very well.
- Within the Padmount Transformer foundations equipment class 151,200 devices are rated excellent.
- *Within the Street Lights equipment class* 156,000 *devices are rated very good,* and 12,000 are rated excellent.
- Within the Poles and Structures equipment class 410 devices are rated good, 873,330 are rated very good, and 10 are rated excellent.
- *The average rating of the asset class is very good.*

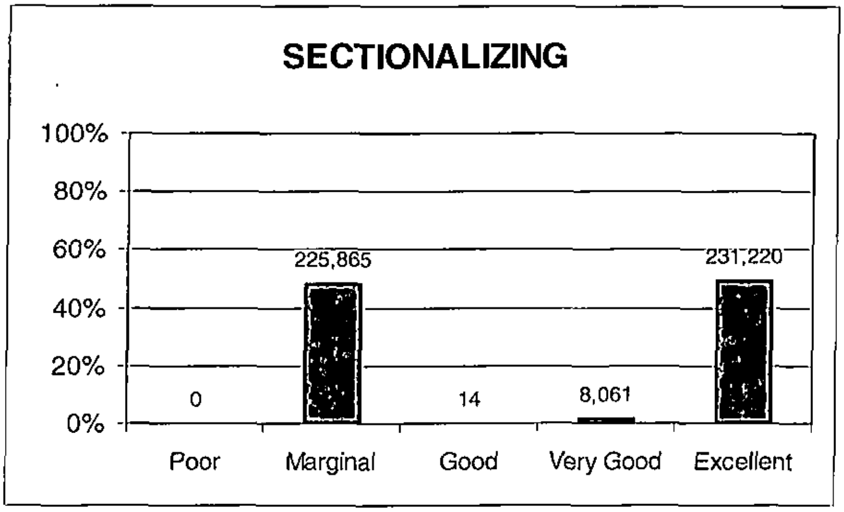


Distribution Transformers

Within this Asset Class the Health Rating of the five (5) individual Equipment Classes were rated from Excellent to Good.

- The largest Equipment Class in this asset group is Overhead Transformers with 375,000 rated Very Good.
- Within the Pad Mounted Transformer Equipment Class there are 77,100 rated Very Good.
- The Network Transformer Equipment Class includes 330 devices all of which are rated Good.
- The Network Protector Equipment Class also includes 330 devices all of which are rated Good.
- The Connectors Equipment Class of 990 Devices are rated Excellent.
- Cascade, Electric Facilities Data Base (EFD) runs, and data from the System Shops records provided this data.

The average Health Index for this asset class is a Very Good rating.

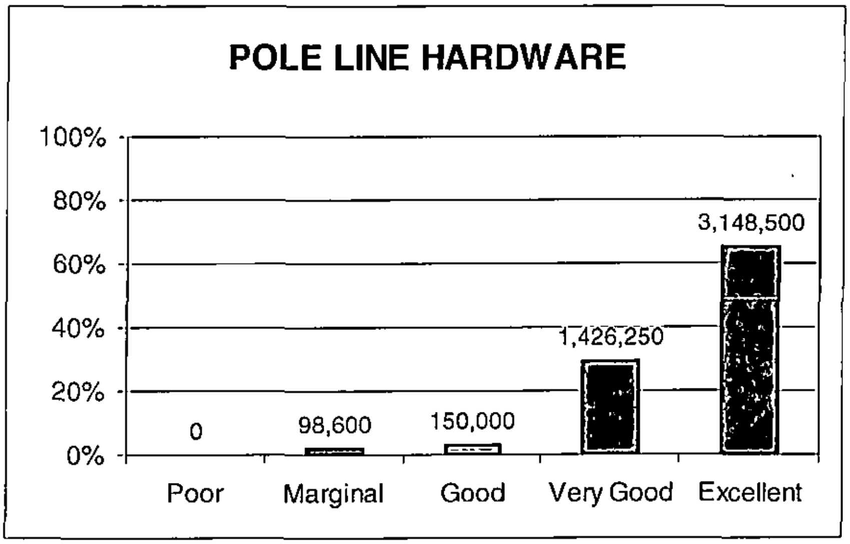


Distribution Sectionalizing

The Sectionalizing asset class consists of 5 equipment classes. Health Index Ratings for the asset class ranged from marginal to excellent.

- Within the Submersible Switchgear equipment class 5 devices are rated good.
- Within the Sectionalizers equipment class 111 devices are rated excellent.
- Within the Reclosers equipment class 4,940 devices are rated excellent.
- Within the PMH Switchgear equipment class 50 devices are rated very good, and 1,000 are rated excellent.
- Within the Switches equipment class 225,865devices are rated marginal, 3,100 are rated very good, and 230,080 are rated excellent.
- The average rating of the asset class is Good.

- The sectionalizing equipment for overhead distribution lines rated marginal are:
  - 30- In Line disconnect switches with porcelain insulators
  - 35- 600 Amp loadbreak air switches by Westinghouse or AB Chance
  - 800-Polymer concrete cutouts, load and non-loadbreak by AB Chance
  - 220,000 Porcelain cutouts, load and non-loadbreak



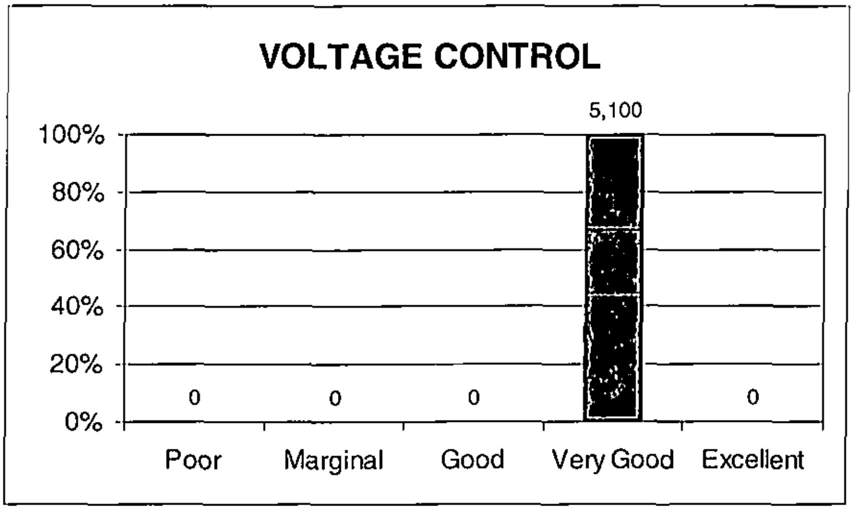
Distribution Pole Line Hardware

Within this Asset Class the Health Rating of the four (4) individual Equipment Classes were rated from Excellent to Poor.

- The largest Equipment Class in this asset group is Insulators with 858,500 rated Excellent, 3,815,250 rated Very Good, 98,500 rated Marginal, and 50 rated Poor.
- Within the Lightning Arrestor Equipment Class there are 450,000 rated Very Good and 150,000 rated Good.
- Within the Street Lights Equipment Class there are 390,000 devices, all of which are rated Excellent.
- In the Anchor Guy Equipment Class 51,000 were rated Very Good and 100 were rated Marginal.
- EFD Data Base runs and Distribution Maintenance estimates provided this data.

The average Health Index for this asset class is a Very Good rating

- The insulators rated marginal are:
  - 7,200-Porcelain insulators with bails
  - 14,000-Anderlite brackets
  - 5,000- Non-porcelain deadend insulators by Locke & Permali
  - 7,200-Porcelain post insulators
- The 50 non-porcelain pin type insulators by Dexmar were rated poor
- The 100 wood anchor guys were rated marginal

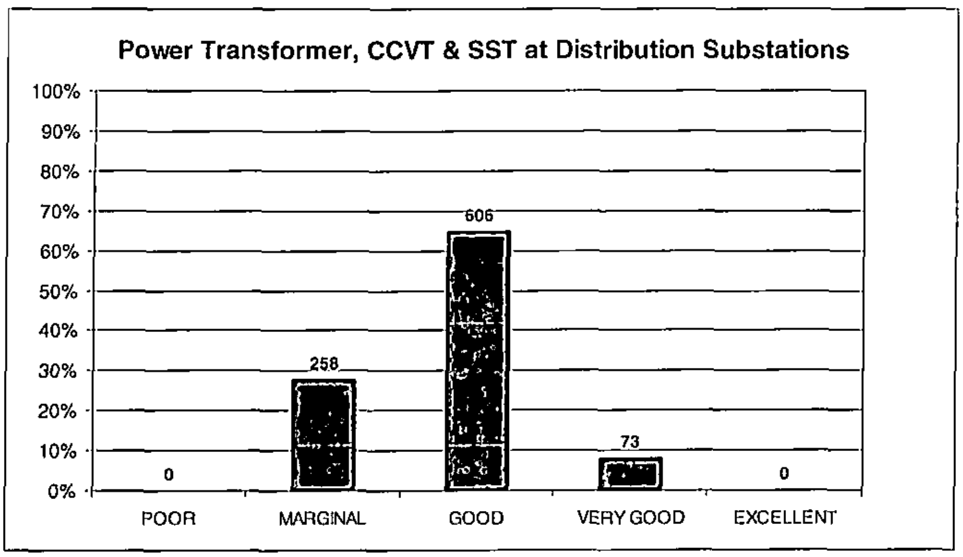


Distribution Voltage Control

This asset class consists of 3,400 Capacitors in Switched Capacitor Banks, 1,500 Capacitors in Fixed Capacitor Banks and 200 Voltage Regulators. This information was retrieved from EFD Data runs, SFC records, a workload study by Distribution Operations, and Inspection Data.

The average Health Index for this asset class is a Very Good rating

3.6.2 Substation Equipment

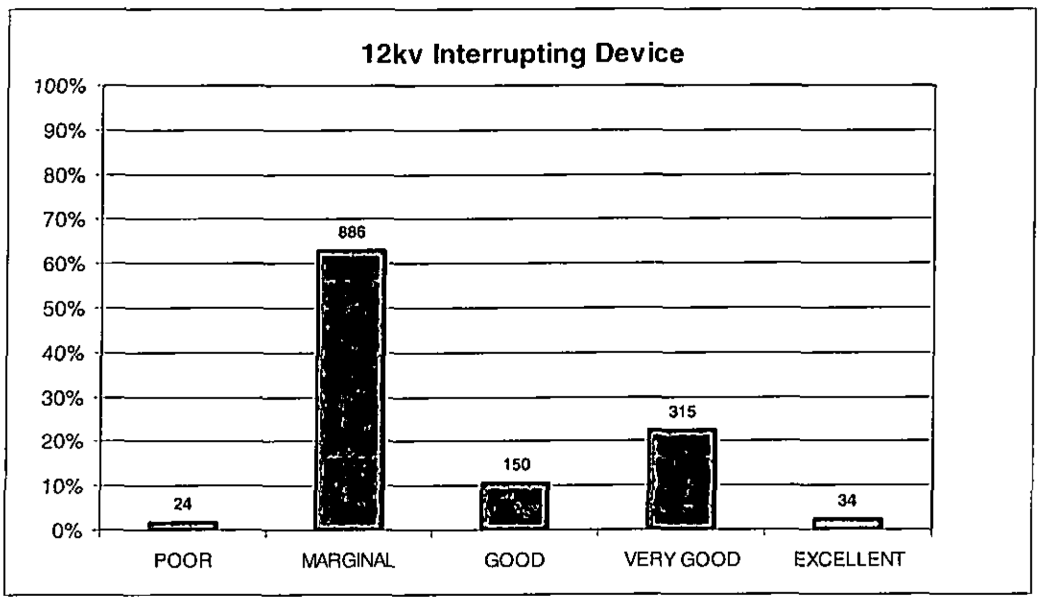


The "Power Transformer" asset class consists of the following equipment classes with device quantities as noted:

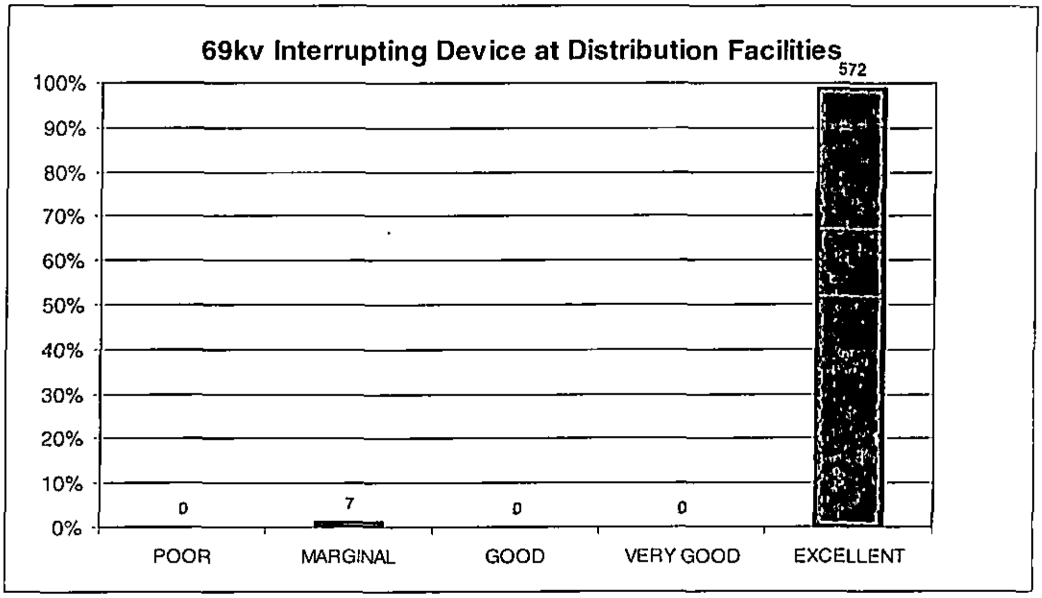
Device	Distribution
Three-Phase Power Transformers	594
Voltage Regulators	33
Coupling Capacitor and Resistive Voltage Transformers	149
Potential Transformers	161

The Health Index of the class combined has 28% of the population rated "Marginal" with the balance "Good" or better. The "Marginal" group is comprised of 69-12kv self-cooled transformers, the rating for which is largely determined by the shape of the age distribution graph and the recognition of the "wave" of aging units which will all come due in the same timeframe for replacement consideration.

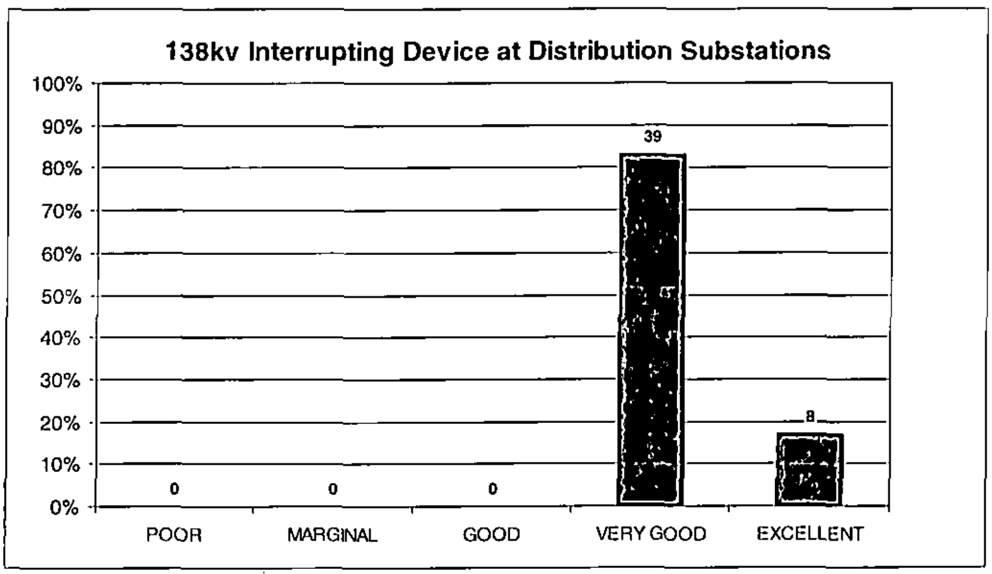
Also included in the "Marginal" category are the six 138kv GE type CD-31 CCVTs at Allentown Substation. GE type CD-31 CCVTs have industry and PPL history of violent I/S failures. A program presently exists to systematically eliminate GE CD-31/51 devices within the next 10 years. However, the six CCVTs at Allentown Substation are being replaced in 2008 as part of a CB replacement.



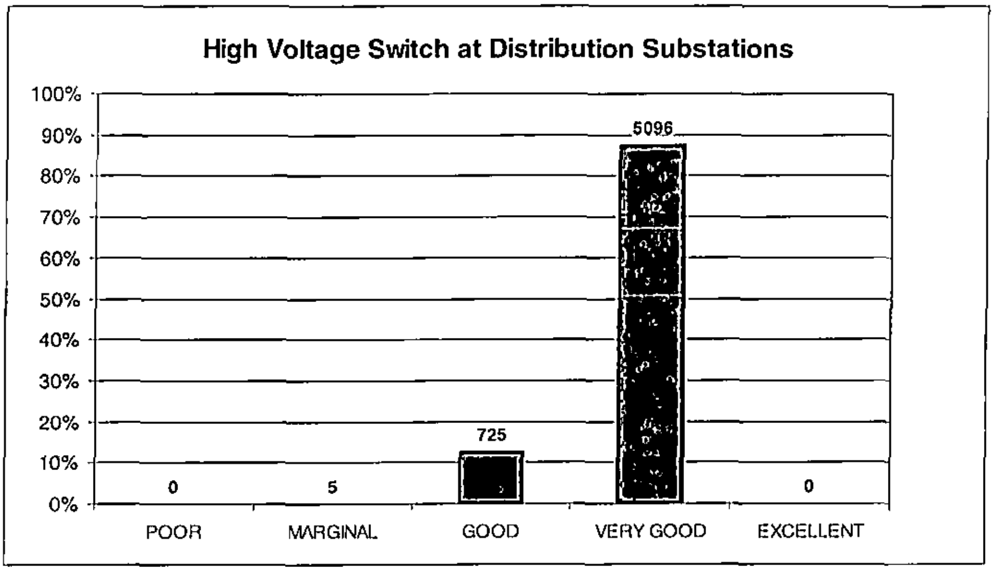
The "12kv Interrupting Device" asset class contains 1398 oil, SF6 gas and vacuum power circuit breakers as well as 11 oil circuit reclosers located within the substation. The Health Index of the class combined has roughly 2/3 of the population categorized as "Poor" (2%) or "Marginal" (63%) largely attributed to the age of the population, operational problems associated with particular breaker styles/mechanism types, and lack of vendor support for spare parts and technical advice.



The "69kv Interrupting Device" asset class contains 7 circuit switchers and 572 three-phase sets of power fuses. The Health Index of the class combined can largely be categorized as "Excellent" representing the power fuses exclusively. However, the 7 circuit switchers are rated "Marginal" (1%) because they are of a design vintage no longer supported by the manufacturer.



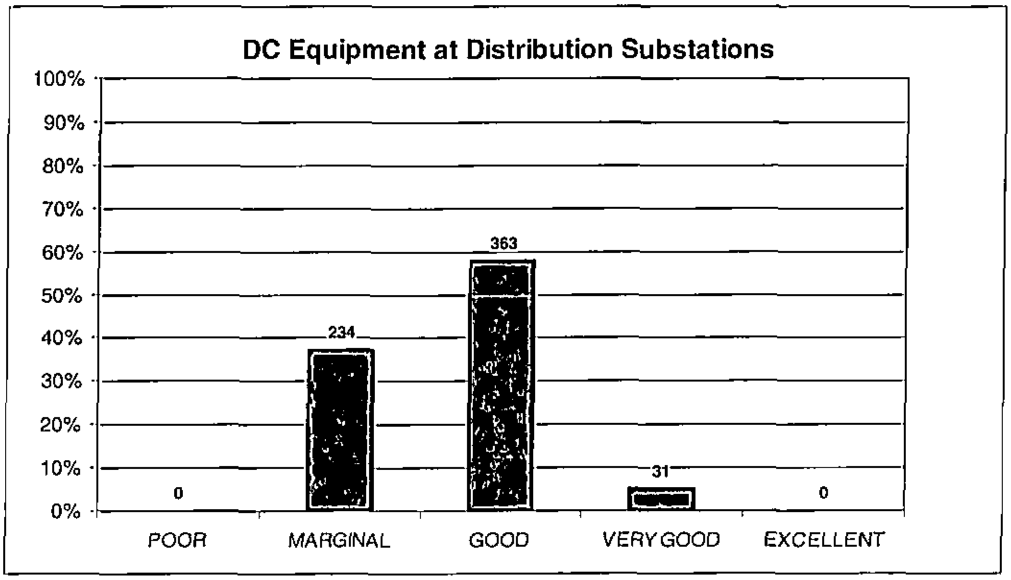
The "138kv Interrupting Device" asset class contains 39 circuit switchers and 8 three-phase sets of transrupters. The Health Index of the class combined can be categorized as "Very Good" or better due to the relative young age of PPL's 138kv systems.



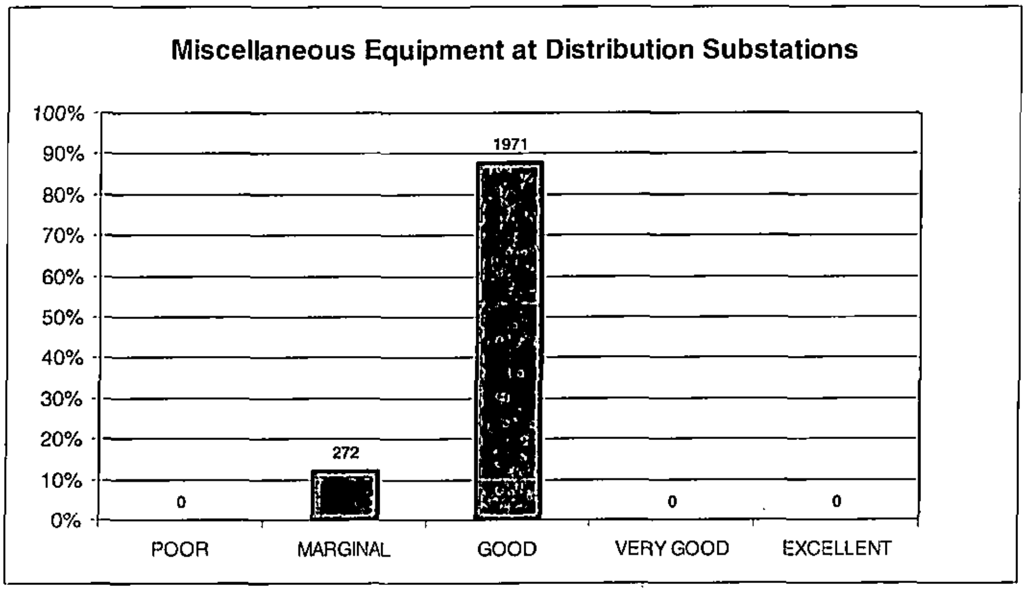
The "High Voltage Switch" asset class consists of the following devices and quantities:

Device	Distribution
Hand-operated, Group-actuated Air/Disconnect Switch	643
Motor-operated, Group-actuated Air/Disconnect Switch	33
Single-pole, Stick-operated Disconnect Switch	5090
Automatic Ground Switch	11
Vacuum Switch	49

The Health Index of the class combined can almost exclusively be categorized as "Good" or better. There is a quantity of 5 vintage propellant-type automatic ground switches which are categorized as "Marginal" but, based on low quantity, is < 1% of the total population in this asset class. The device requires a specially-designed 'shotgun shell' charge to operate which is no longer manufactured. PPL Stores had previously purchased a limited quantity available of these charges once it became apparent the design was no longer supported. This will suffice in the near term for operational replacements however, there is not adequate supply to support periodic testing of the device (must be fired) to ensure correct, ongoing performance. This device is included in the present Asset Modernization program for systematic replacement with current technology not requiring the specialized charge.



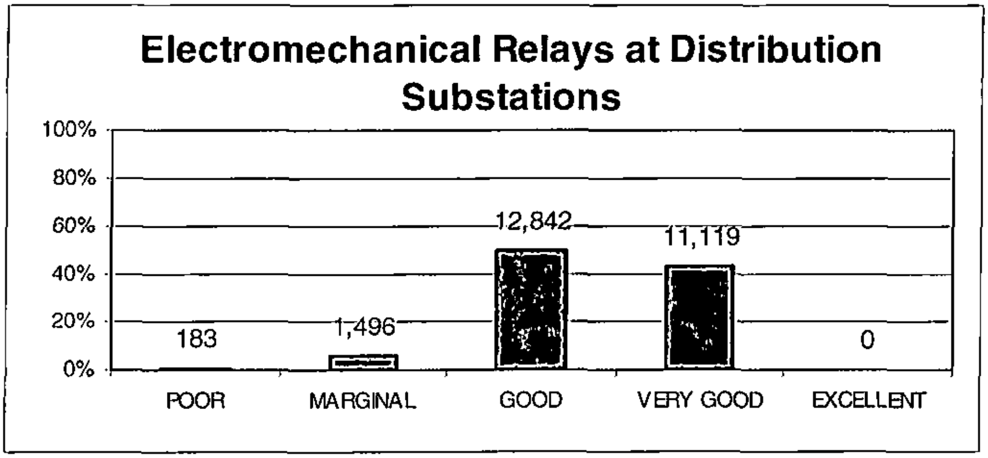
The "DC Equipment" asset class consists of 312 lead acid batteries and 316 battery chargers. The Health Index of the class combined has 37% of the population rated "Marginal" with the balance "Good" or better. The "Marginal" group is exclusively comprised of 234 48-volt battery chargers which have a relatively high average age and problematic operation/replacement parts issues by vendor and charger model.



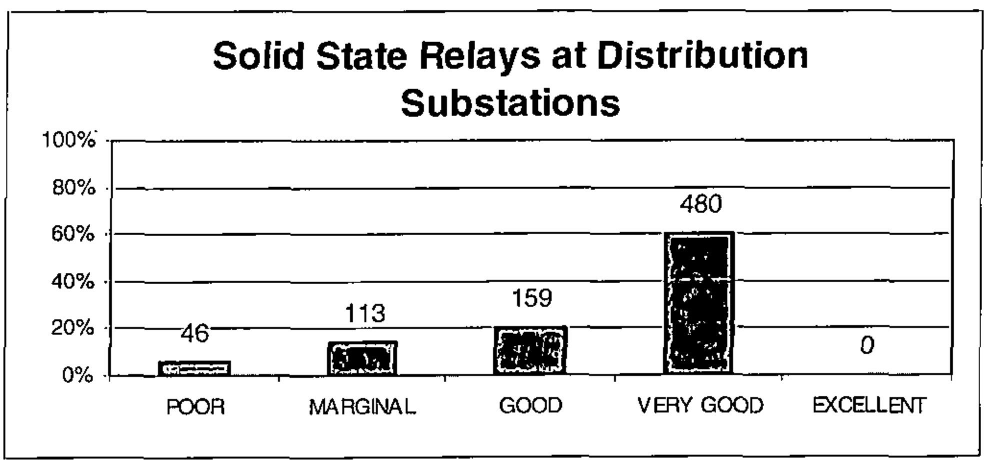
The "Miscellaneous Equipment" asset class consists of 272 "Distribution Cable (3-phase circuit)" and 1971 "Surge Arrester" equipment classes. The Health Index of the class combined is largely categorized as "Good" or better with only 12% rated Marginal".

The "Marginal" category is comprised exclusively of 12kv solid-dielectric cable used for both underground transformer leads and bus section cross yard tie applications (line terminal getaways are excluded; covered under the Distribution MOS assessment). With the average age of the population being 29 years, a higher I/S and Doble test failure rate is being observed.

3.6.3 Protection and Control

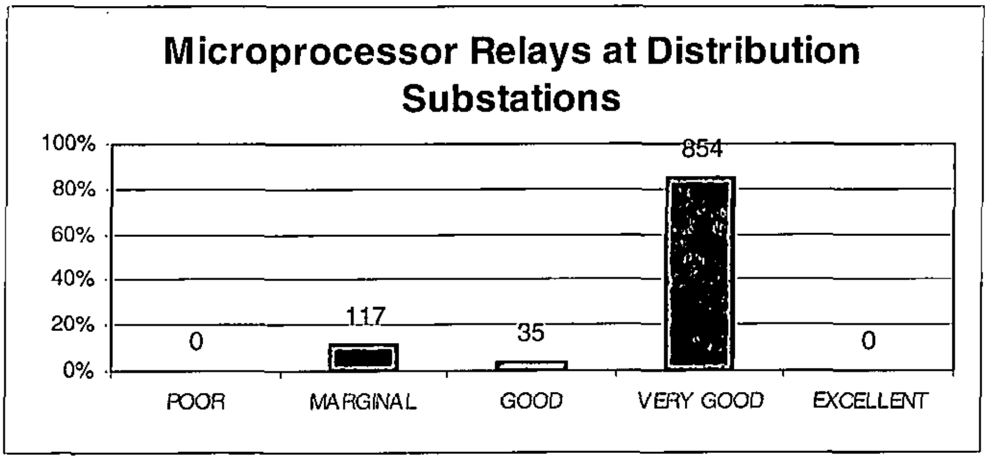


The Electromechanical Relay Asset Class contains 25640 relays within the following six (6) Equipment Classes: Auxiliary, Differential, Frequency, Overcurrent, Reclosing, and Voltage. The Health Indices of this Asset Class range from Very Good to Poor. Equipment with a Marginal Health Index (1496) includes aging auxiliary, GE type AC-1 reclosing, and GE type PCV voltage relays. Equipment with a Poor Health Index (183) includes aging and obsolete GE type IA201 overcurrent, Westinghouse type RC reclosing, and GE type CFF frequency relays. For these components, higher than expected failure rates are being observed thus requiring frequent maintenance to maintain reliability. The average Health Index for the Electromechanical Relay Asset Class is Good.

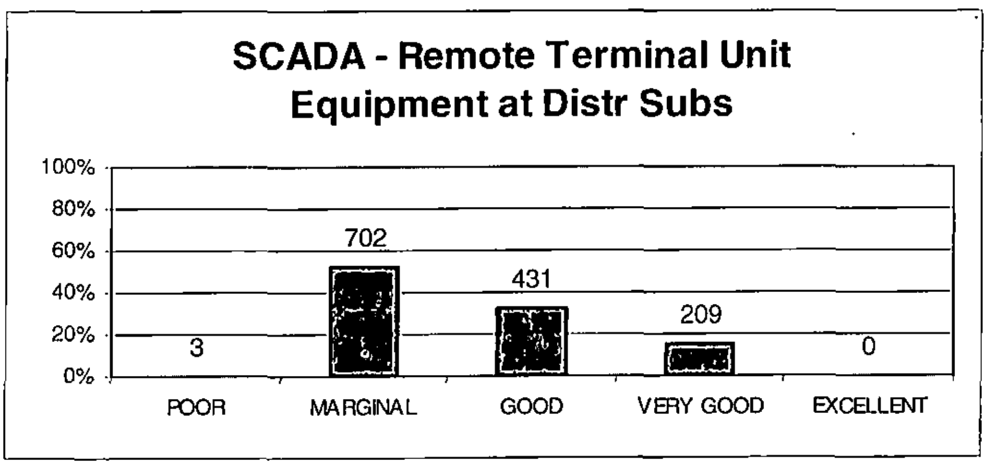


The Solid State Relay Asset Class contains 798 relays within the following three (3) Equipment Classes: Auxiliary, Multifunction, and Single Element. The Health Indices of this Asset Class range from Very Good to Poor. Equipment with a Marginal Health Index (113) includes aging Beckwith M-0318 capacitor bank protection and GEC

MBCH bus differential relays. Equipment with Poor Health Index (46) includes auxiliary Amerace SSF timer relays that have proven unreliable during power system transient conditions. The average Health Index for the Solid State Relay Asset Class is Good.



The Microprocessor Asset Class contains 1006 relays. The Health Indices of this Asset Class range from Very Good to Marginal. Equipment with a Marginal Health Index (117) includes aging and obsolete ABB DPU-245/445 feeder protection relays with high failure rates. There is a currently a capital replacement program to replace these first-generation microprocessor relays over the next five (5) years. The average Health Index for the Microprocessor Relay Asset Class is Very Good.



The SCADA – Remote Terminal Unit Asset Class contains 1345 devices, including controllers, transducers, input/output modules, and power supplies. The Health Indices of this Asset Class range from Very Good to Poor. Equipment with a Marginal Health Index (702) includes aging obsolete Leeds and Northrupp, Ferranti, and legacy TRW SCADA controllers, transducers, and cabinets. Equipment with a Poor Health Index (3) includes obsolete Harris – Micro 1 SCADA controllers with higher than average failure rates. The average Health Index for the SCADA – Remote Terminal Unit Asset Class is Good.

4 Capital Replacement Program

As demonstrated by the age charts throughout this section, many equipment classes contain devices which were installed in significant quantities during times of more robust system expansion and development, such as the early 1970's. This has caused a "wave" or "bubble" effect in age plots as the assets age over their expected lifetimes. As can be seen, in the power transformer and the electromechanical relay charts, the equipment represented by these waves will be approaching their expected end-of-life within the next 10 to 20 years with overwhelming capital expenditure requirements to properly address replacement of these assets. In some cases, a portion of a device class has already exceeded this end-of-life target.

The plan to develop the Capital Replacement program can be summarized by these steps:

- Develop a PPL Expected Life

  The PPLE MOS team reviewed the Plant Accounting Book Life for each of the asset classes. Today, there are only 4 different values for book life for all of the components of the T&D system. While this may be adequate for calculation of depreciation of the system, it is difficult to utilize this in a condition assessment, or capital replacement project. Everyone understands that the expected life of a computer or other electronic component cannot be as long as the life of the conductors used for our lines.

  The teams reviewed the average age, the maximum age, any recommended values of expected or design life provided by manufacturers, and the general condition of the equipment to estimate the "PPL Expected Life" used in the analysis of the aging assets.
- Develop a method of evaluating the condition of the aging assets, and determine a methodology to identify those deteriorated sufficiently that they should be replaced.
  - Utilize the transmission line section evaluation criteria that is detailed under methodology below, or
  - Determine the number of units to be replaced in the 10 year capital replacement budget window to maintain the asset group within the PPL expected lifetime. This will be the proposed budget request to fully implement a program to avoid the problems of allowing the aging infrastructure to continue to grow older.
-
- When the budgeting process reaches the point of planning projects to implement the replacements, the condition assessment graph will identify which of the assets (by group) should be done first. Example: The GE CBs which had the worst condition rating on the example chart would be identified as the highest priority within the CB asset class.

- After the condition assessment and capital replacement program are established for all equipment, either the MOS team, or a follow up project, will need to develop the criteria to determine how to rank priorities and identify synergies when comparing transmission equipment to distribution equipment to substation equipment replacements. We anticipate that the importance of the equipment to the system operations, and consequences of failure would be primary drivers of that analysis (along with reliability impacts, financial returns, worst performing circuits program, etc.)

- Project the cost of the overall replacement program.

4.1 Capital Replacement Methodology

The Capital Replacement Plan was developed by three different sub teams. Based on data availability, and a determination of viable project work scopes, each team used slightly different methodologies. The three methodologies are described in this section.

4.1.1 Distribution Equipment

The MOS team recommends developing a capital replacement strategy based on rebuilding the distribution lines and line segments that have experienced an unusually high number of outages due to failed equipment. The recommendation is to completely reconstruct these facilities on a planned basis rather than spending considerable and increasing expense dollars for routine maintenance on an existing line. The complete reconstruction ensures that a line section and its components are modernized with new and reliable materials; and designs that are expected to reduce long term life cycle maintenance expenses.

A few large quantity items that have been in service beyond their expected life cycle can be easily identified from EFD records. The MOS team recommends replacing those items, utilizing complete reconstruction. Funding and resources should be provided to ensure that all of this material is replaced within the next twenty years.

The following material should be included in this recommended capital replacement program;

- #6 Cu, #6CW, #6ACWC and #7A CWC overhead conductor
- 1-3/c 15 kV PILC underground cable
- Manholes and Vaults with known structural concerns
- 600 V Cu Lead secondary cable
- Submersible Transformers and Network Protectors in corrosive environments

The MOS team's long term methodology is specifically outlined in the following section.

Current Plan for Overhead Equipment

The majority of overhead outages on the distribution system occur due to damage, not deterioration of equipment. Damage from severe weather conditions, contact with trees, automobiles and construction accidents, fires and vandalism are the main causes of overhead distribution equipment failures.

Overhead distribution equipment is also often replaced prior to the end of its expected useful life due to line reconstruction resulting from load growth, storm damage, reliability improvement projects, or forced relocations by outside agencies.

The basic equipment for the overhead distribution system (Poles, Conductors, and Insulators) is robust and has an expected life span in normal service of 50 years or more. *PPL has few or no records for the equipment installed on a particular structure.* Therefore, it is very difficult to determine the manufacturer, model, rating or age of the equipment. The MOS team has not developed a program to replace the aging assets based on a combination of age and evaluated condition.

Current Plan for Underground Equipment

Most outages on the underground equipment are due to cable deterioration and subsequent failures. Most others are caused by construction accidents and vandalism. The limited amount of routine testing and monitoring programs currently used on known problematic equipment does provide some information and feedback as to the expected remaining life for the installed underground distribution equipment.

Excluding extreme cases where failure is imminent, the current monitoring and testing provides data that can usually determine when the equipment is about to fail.

Recommended Plan for Overhead Equipment

The MOS team recommends that PPLE develop a formal visual inspection program for the overhead distribution system. Inspection is the chief means of determining the overhead distribution system's condition and should be considered as the main method to determine a long term capital replacement plan.

It must be performed with a high level of accuracy and the results stored and *accessible in a reliable and flexible database system. The results must identify* equipment damage and also detect signs of deterioration. The new equipment failure database that will be implemented in 2009 is capable of supporting the proposed inspection and record keeping initiatives. The use of this data would allow PPLE to develop criteria that could be used in future condition assessment studies, and to provide justification for the capital replacement of overhead distribution equipment known to adversely affect the reliability of the distribution system.

Recommended Plan for All Distribution Equipment

Based on the results of the health index for distribution equipment, the team recommends replacing the large quantities of deteriorating primary overhead conductor, underground cable, and low tension network structural and electrical facilities noted in this report.
We also recommend that the overhaul program for the OCRs, VCRs and Sectionalizers be changed to an eight year cycle rather than the existing ten year cycle.

Distribution Circuits Replacement Program

In addition, a capital equipment replacement program should be established to identify a select group of distribution circuits that have exhibited unusually high equipment failure rates during the past several years. Equipment will be replaced on a per circuit basis where the greatest risk of failure exists, based upon available historical reliability information, as well as health assessment data.

The estimated costs ($/circuit and $/mile) to replace equipment with known unusually high failure rates was developed using the following methodology logic:

- Determine the total estimated quantities, capital and maintenance costs for the top ten equipment types on the team's 'worry list' for the PPL system.
- Calculate the approximate amount of the equipment that should be replaced by dividing the total number of units on the team's 'worry list' by the total number of distribution circuits (approximately 1,100). This provides a good estimate of the quantity of units per circuit. The team has assumed that 20% of the circuits are adequate and will not require replacement in the 2010 – 2020 time span.
- Further refine the quantity of units per circuit by calculating the number of single phase and three phase installations for the equipment where applicable. This ensures that labor and material costs reflect the actual ratio of three phase and single phase circuits on the PPL system.
- Calculate the average miles per distribution circuit on the PPL system by dividing the total circuit miles by the number of circuits on the system (25.3 miles per circuit).
- The final capital replacement cost per circuit mile is then calculated by dividing the sum of the cost to replace the estimated quantities of units per circuit by the number of miles per circuit. The recommendation is that all resulting circuits should be addressed in the next 10 years. That results in 100 circuits per year.

The estimated cost to replace this equipment on a per circuit basis is $140,000, or $6,000 per circuit mile.

To help mitigate the risk of incurring additional equipment failures and resultant power interruptions, the team has recommended that $1,400,000 in capital be included in the annual budget to fund this program. The methodology used to select and prioritize the circuits should focus on both historical reliability performance and the relative health of the circuits and associated equipment.

This multi-step capital replacement methodology provides a solid foundation for replacing the distribution facilities that have reached, or are quickly approaching, the end of their useful equipment lives; and are significantly affecting the reliability indices. Implementation of this plan is required to reduce distribution operating and maintenance expenses as recommended in the maintenance strategy section of this report.

4.1.2 Substation Equipment

Prior to this initiative and the recognition that our aging infrastructure should be addressed with a proactive program to begin replaced old worn out equipment, maintenance was viewed differently. A common opinion was that most major equipment could be maintained and repaired less expensively than it could be replaced, [not considering the corporate value of an "expense dollar" versus a "capital dollar"]. As such, most personnel involved with substation physical/electrical equipment had by default adopted a rather informal "run to failure" methodology for a replacement strategy.

Moving forward, the primary considerations for prioritizing a program for substation capital asset replacement are:

- Age, both individually and as an equipment class
- Overall health index of the equipment class group
- Criticality of the specific equipment system function or circuit to which it is connected.

As demonstrated in the age charts throughout this report, many equipment classes contain devices which were installed in significant quantities in more robust system expansion and development years such as the early 1970's. This has caused a "wave" or "bubble" effect as the assets age over their expected lifetimes. As can be seen, especially in the 69-12kv power transformer chart, these waves will be approaching their expected end-of-life within the next 20 years or sooner with significant capital money requirements to properly address the problem. In some cases, a portion of a device class has already exceeded this end-of-life target with these units literally operating on borrowed time.

The goal of the capital asset replacement strategy used in this report for substation physical/electrical assets is to levelize the age distribution within a device class, beginning with older units, those having known operating/maintenance issues and portions of the oncoming wave, such that annual capital replacement dollars can be budgeted without a significant variance from year-to-year. The overall health index will be used in conjunction with age data to apportion the dollars to the specific equipment and device classes that have the most system impact.

The last consideration noted above (condition) is most often used to prioritize the replacement strategy within the equipment groups that have a large population and a relatively higher cost to replace (i.e.: Type "U" bushings or 69-12kv power transformers).

4.1.3 Protection and Control Equipment

A strategy for detecting and dealing with failing protection system components is important to improving the reliability of the distributions system and should be the main factor with regard to the development of a capital replacement program.

Considerations used to determine a protection and control capital replacement program are the following:

- Levelize capital budget for replacement of aging assets
- Circuit criticality and impact of failure
- Health index or condition assessment of the component
- Added value and enhanced capabilities of modern protection and control equipment
- Maintainability of the asset; that is, ease of maintenance on the asset

Existing protection and control equipment needs to be periodically evaluated to ensure maximum reliability and security. As illustrated in the protection and control age histograms, a fair number of equipment classes are approaching their life expectancy over the next ten (10) years. To properly address this aging infrastructure, a formal capital replacement program is essential. In some cases, a portion of a device class has already exceeded this end-of-life target with these units literally operating on borrowed time. Additionally, our ability to maintain protection and control systems has been degraded by component obsolescence, lack of spare components, and limited vendor and technical support for our oldest equipment in particular. All of these concerns are directly related to the age of the asset.

One of the goals of the protection and control capital replacement strategy used in this report is to levelize the age distribution within a device class such that annual capital replacement dollars can be budgeted without a significant variance from year-to-year. The plan is to begin with oldest units and those having known maintenance and reliability issues. The overall health index will be used in conjunction with age data to apportion the dollars to the specific equipment and device classes that have the most system impact.

In order to effectively replace aging protection and control assets, it is estimated that approximately $2.2MM per year ($23MM over a ten-year period) must be budgeted. This will ensure that the assets do not exceed their life expectancy, operate in a secure and reliable manner, provide added-value such as event recording and self-diagnostics, and increase the maintainability of the asset by significantly reducing the number of components and wiring terminations.

The results of the condition assessment (i.e. Health Index) will initially determine the protection and control equipment considered for the capital relay replacement program. Obsolete electromechanical relays, such as the Westinghouse CO and General Electric IAC overcurrent relays and associated reclosing relays are immediate candidates for a relay capital replacement program. Additionally, the first generation microprocessor distribution relays, such as the ABB DPU-245/445, have shown an increasing failure rate. These relays are rapidly approaching their end-of-life. For a typical distribution feeder, a modern microprocessor relay can replace up to fifteen (8) electromechanical and/or solid-state relays, thus reducing (by up to 50%) periodic maintenance and testing requirements for the device. The expected annual expense savings due to electromechanical and solid-state relay replacements is $100K.

To better define relay replacements on the distribution system, we will use circuit criticality, worst performing circuits, and substation design types (e.g. Type B substations) to prioritize relay replacements. The program must consider the criticality of the facility itself from a power delivery perspective and the criticality of the relay and control scheme assuming the system is normal. It is realized that system facility and protection and control device criticality assignments will need to be revised periodically based on facility upgrades.

Modern protection and control equipment being installed as part of a capital replacement program will provide added value and enhanced capabilities. New relay technologies can predict maintenance activities by trending items such as circuit breaker operating times, trip coil current, and temperatures. In addition, new relay technologies can also determine fault type, location and incipient cable insulation failures. Microprocessor-based protective relays with fault locating and remote-access control capabilities can assist crews in finding trouble areas much more quickly than by random line patrol.

Microprocessor-based relays do not require the same periodic maintenance associated with electromechanical devices and are equipped with self-test diagnostics that continuously monitor the health of the device. These self diagnostic capabilities offer major advantages over electromechanical relays, which are equipped with no self-checking facility and which are diagnostically tested only at scheduled maintenance intervals. If an electromechanical relays fails, the best case scenario is that failure will be identified during the next scheduled periodic test. In the worst case, the failure presents itself when the relay either does not operate during a system disturbance, or when it operates incorrectly.

To ensure continued performance with regard to the Supervisory Control and Data Acquisition (SCADA) system, legacy SCADA remotes, such as the Harris, Ferranti, and the Conitel systems, shall be replaced with modern PLC-based SCADA systems. These systems are difficult to maintain due to obsolescence, lack of spare parts, and no vendor support. Additionally, the test equipment used to perform maintenance on this equipment is failing, and there are no replacements available. The cost to replace legacy SCADA systems is approximately $6MM over the next several years. Although there are dollars in the 2010-2014 capital budget to replace legacy SCADA systems, it is not adequately funded to replace all systems. Additionally, modern substation SCADA systems will provide future support for a Distribution Automation projects. The existing SCADA systems cannot provide this function.

4.2 Total Replacement Value of Distribution Asset Classes

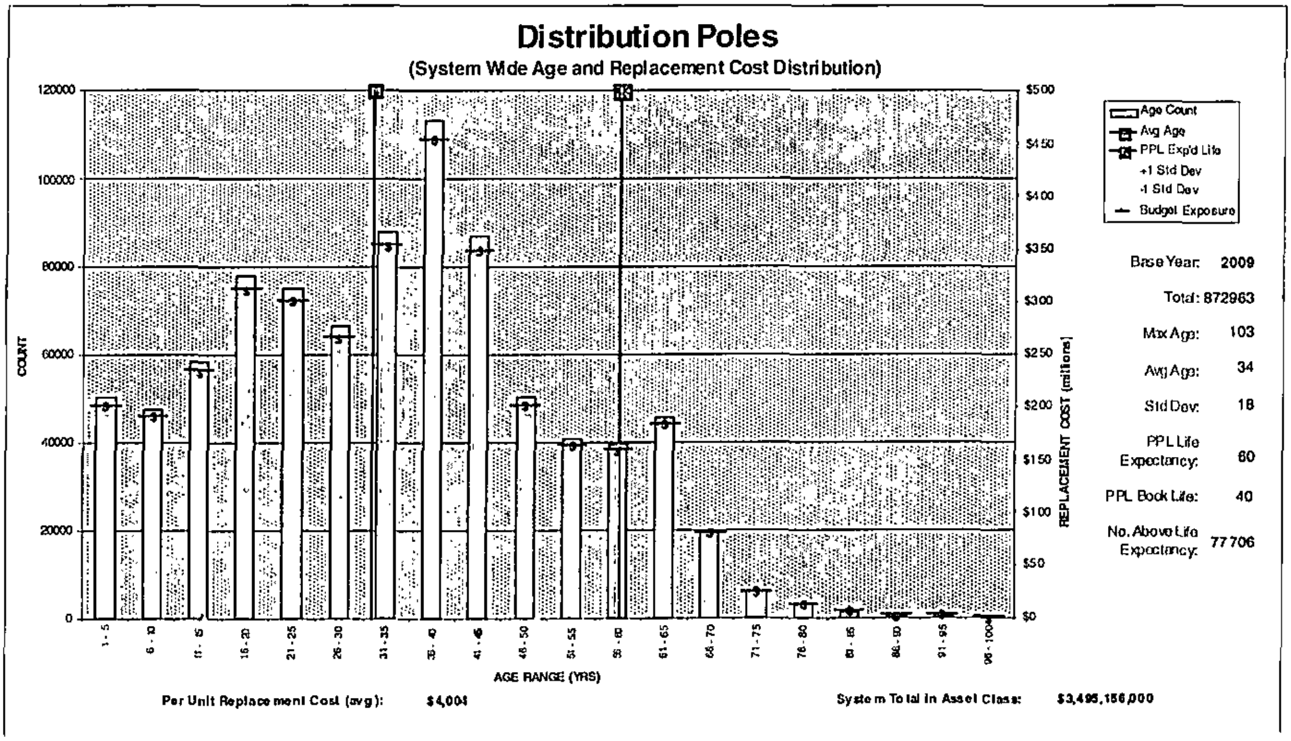
Total Replacement Value of Distribution Asset Classes				
			Replacement Cost	
Asset Group	Asset Class	Population	Units	($ Thousands)
Distribution	Sectionalizing	465,160	Each	503,845
Distribution	Pole Line Hardw are	4,823,350	Each	4,468,350
Distribution	Conductor And Cable	22,486,200	Miles	12,936,200
Distribution	Transformers	453,750	Each	562,500
Distribution	Poles And Structures	1,199,950	Each	5,127,720
Prot & Control	Electromechanical	25,640	Each	55,050
Prot & Control	Microprocessor	1,006	Each	8,197
Prot & Control	Scada - Remote Terminal Unit	1,345	Each	30,672
Prot & Control	Solid State	798	Each	3,878
Substation	12Kv Interrupting Device	1,409	Each	119,325
Substation	138Kv Interrupting Device	47	Each	12,081
Substation	69Kv Interrupting Device	579	Each	2,901
Substation	Dc Equipment	628	Each	9,035
Substation	Miscellaneous Device	2,593	Each	37,465
Substation	Sw itch, HV	5,826	Each	62,258
Substation	Transformer Sub	937	Each	541,336
	Total Distribution System			24,480,813

4.3 Distribution Equipment Age Charts

4.3.1 Distribution

Distribution equipment is considered mass property. The quantity of any specific type of equipment installed on the system is usually very large. With the exception of poles and direct buried underground cables, little or no data exists that reflects the installation date or replacement of the distribution equipment.

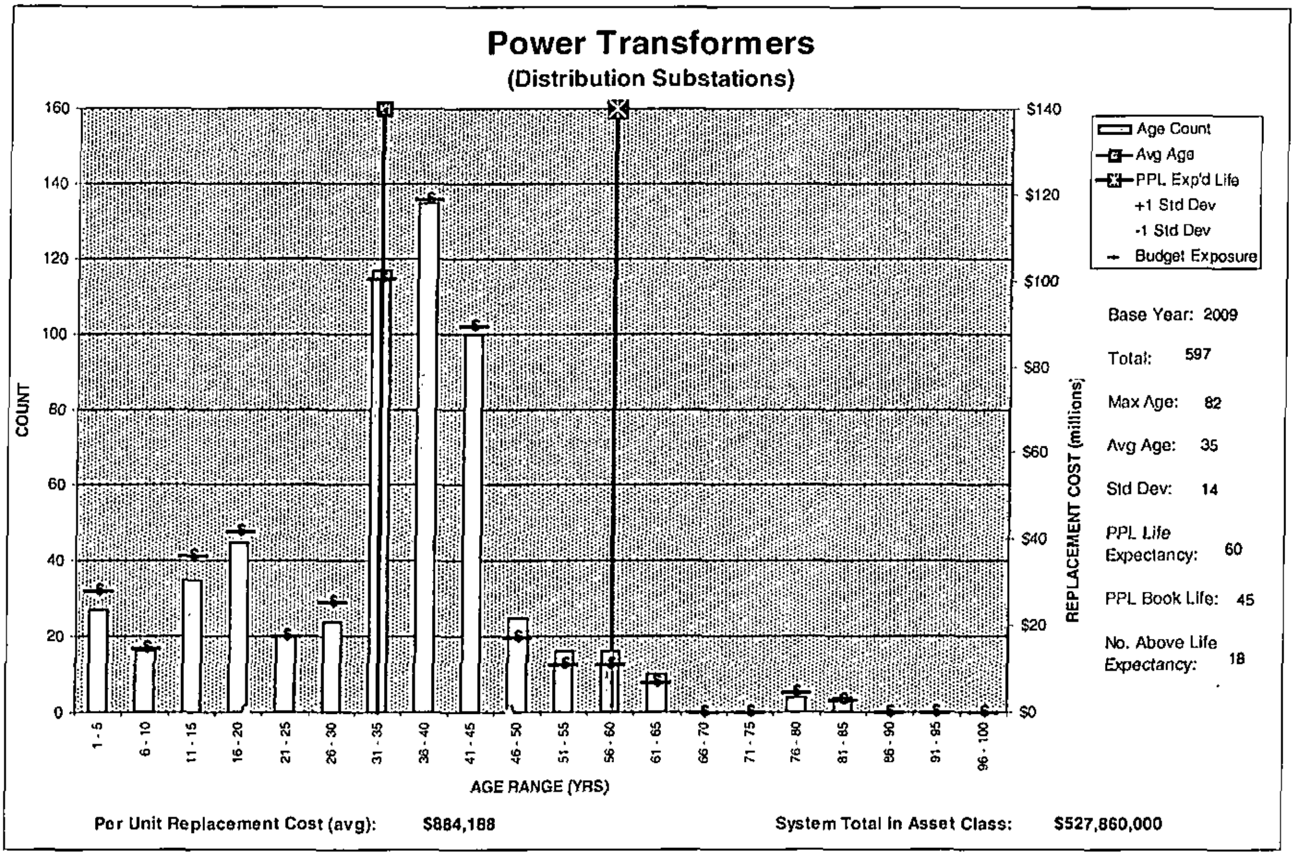
Distribution equipment is robust and typically has a lifespan of approximately 50 years. Damage from severe weather conditions, contact with trees, automobiles and construction accidents, fires and vandalism are the main causes of distribution equipment failures. In addition, distribution equipment is often replaced prior to reaching the end of its expected useful life due to line reconstruction resulting from load growth, reliability improvement projects or forced relocations. As a result, due to the large quantities of equipment installed on the distribution system and the inability to create good records, the age charts for distribution equipment can not be accurately developed.



Poles and Structures

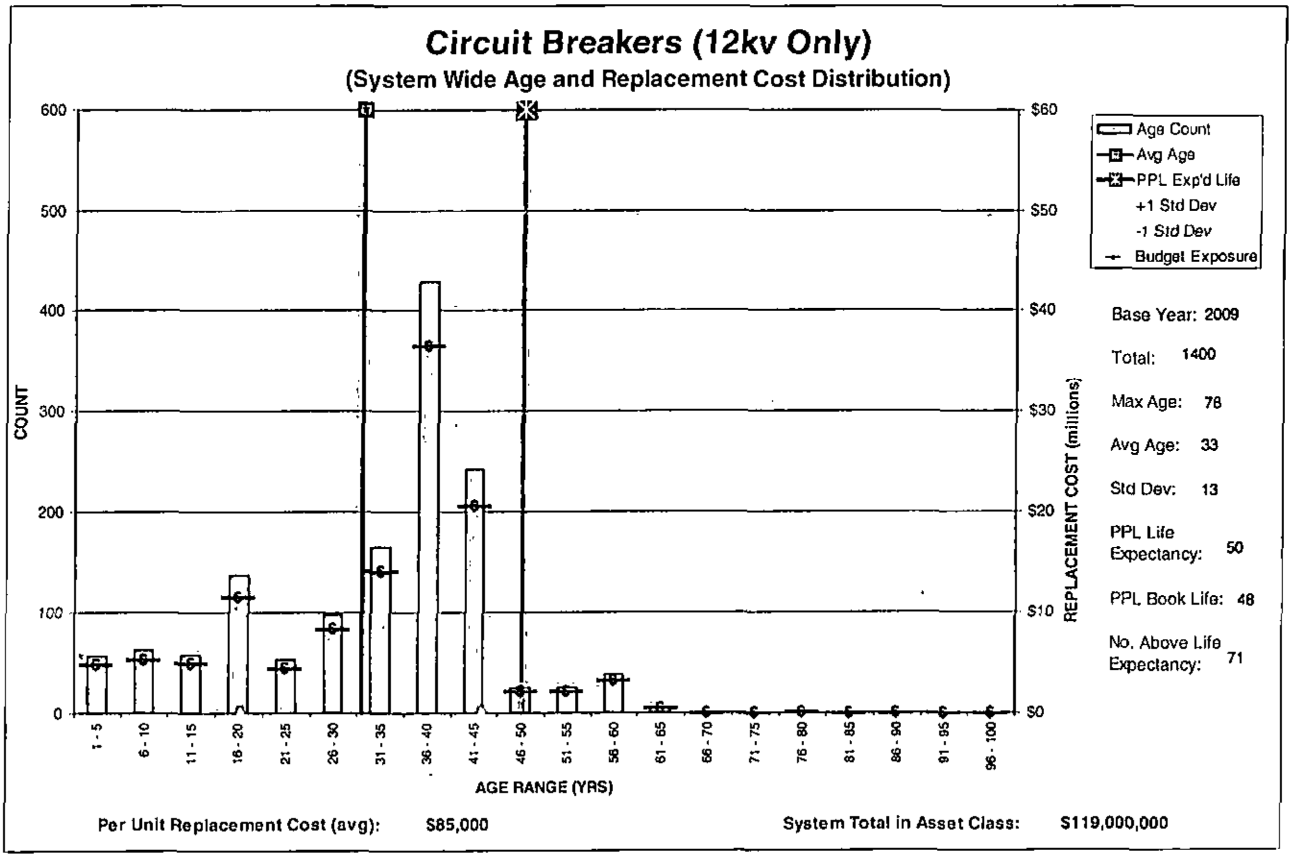
Pole and structure replacements are done routinely throughout each year for the various reasons described. When the entire pole is replaced, it is capital, other work to replace components installed on the pole are expense. The team expects that the past trends will continue, and that the capital expenditures will continue to rise slowly, as the system is expanded

4.3.2 Substation



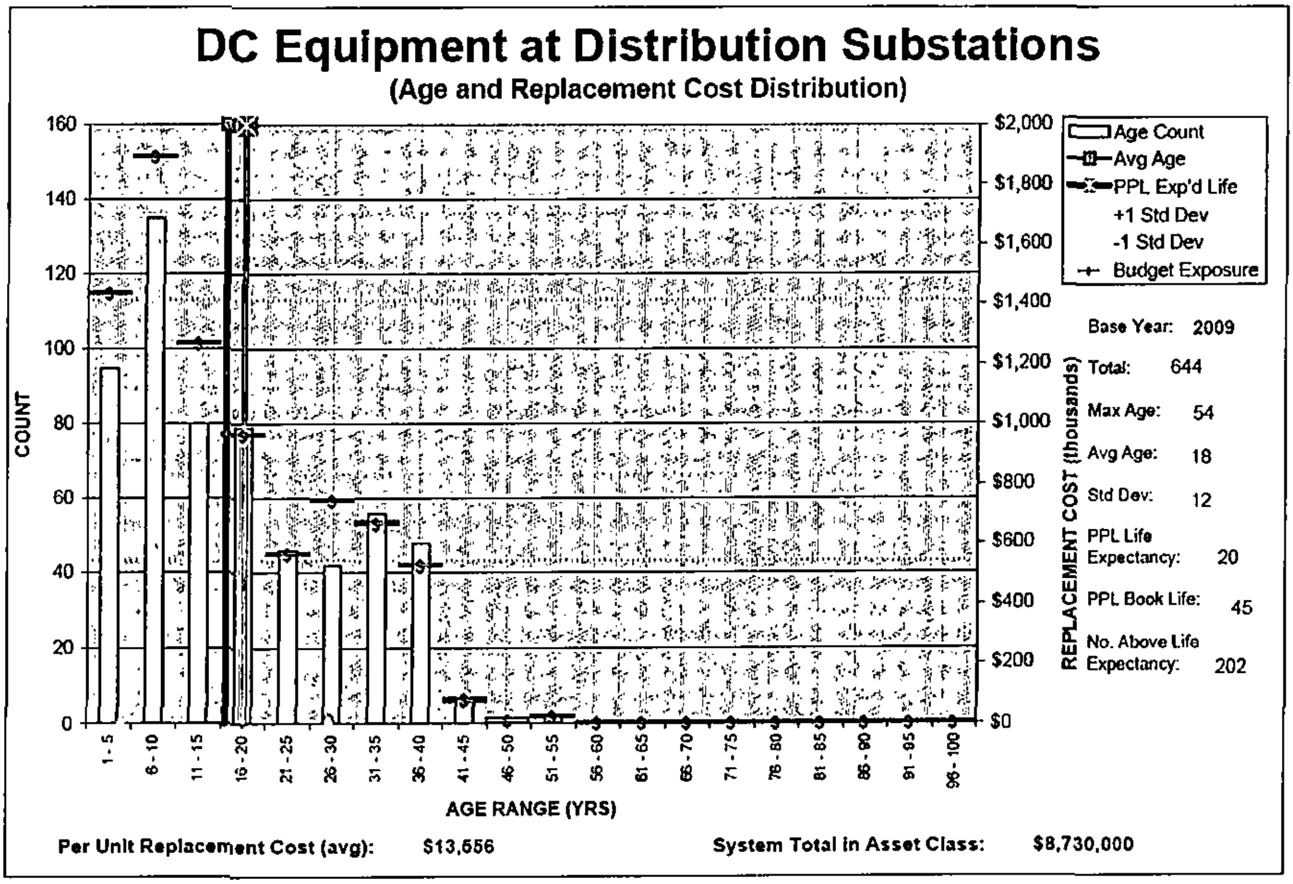
The average of the power transformers in this study is 34 years.
The PPL Expected life is 60 years.
PPLE has 23 units older than expected life.
In 2010 -2015, an additional 21 will exceed the expected life,
In 2015 -2020, an additional 25 will exceed the expected life,

This asset class consists of 594 power transformers and 33 voltage regulators. This information was retrieved from the Cascade substation inventory.
The replacement costs are based on the present estimated delivered costs for new transformers, with standard installation costs. The estimated cost to replace units (so that the maximum age will be under the PPL expected life), and then maintain that maximum age within the 2010 to 2020 window is $200M.



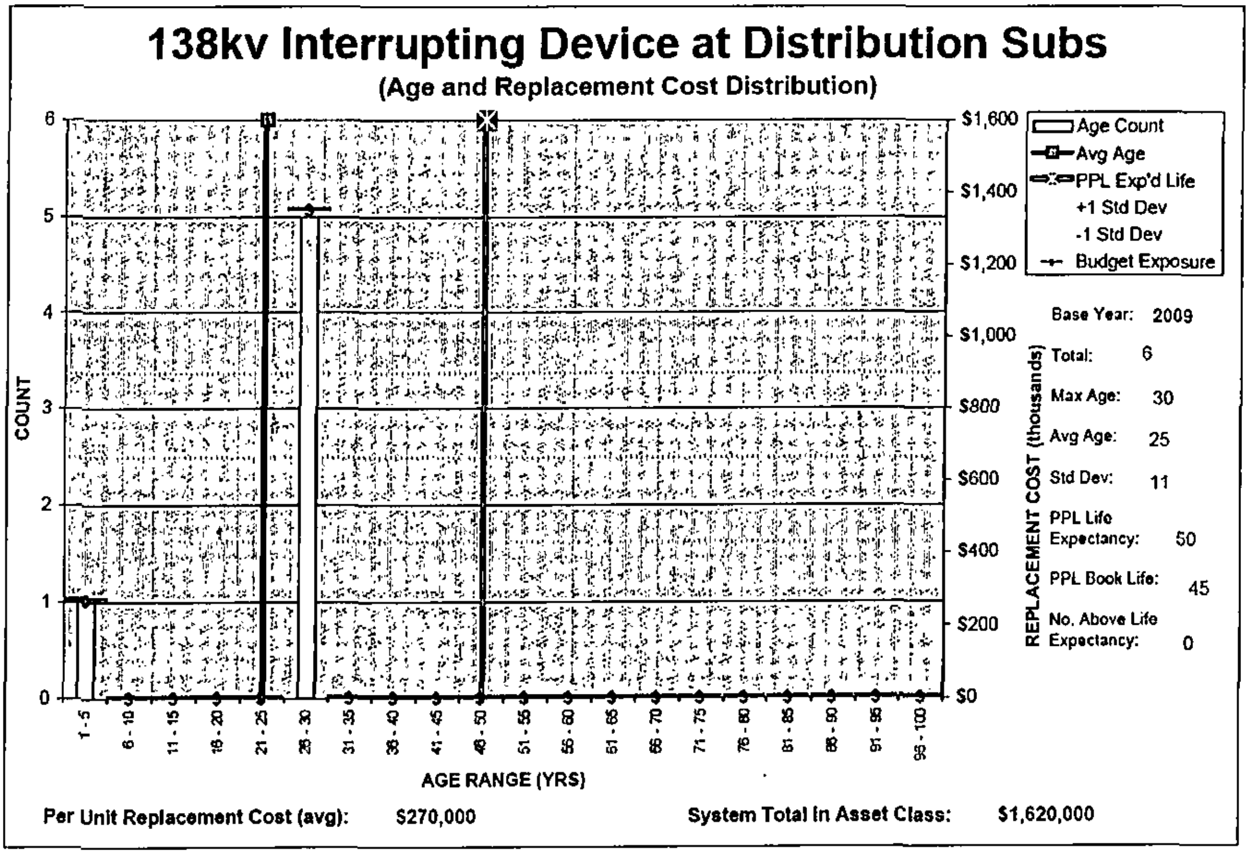
This asset class consists of 1398 oil, SF6 gas and vacuum circuit breakers and 11 oil circuit reclosers; data obtained from Cascade substation inventory.

The replacement costs noted include the circuit breaker or recloser purchase price and standard installation costs. The total estimated cost to replace all units which presently exceed life expectancy is approximately $7MM. The total estimated cost to replace all units which will reach life expectancy within the next 10 years is about $27MM.

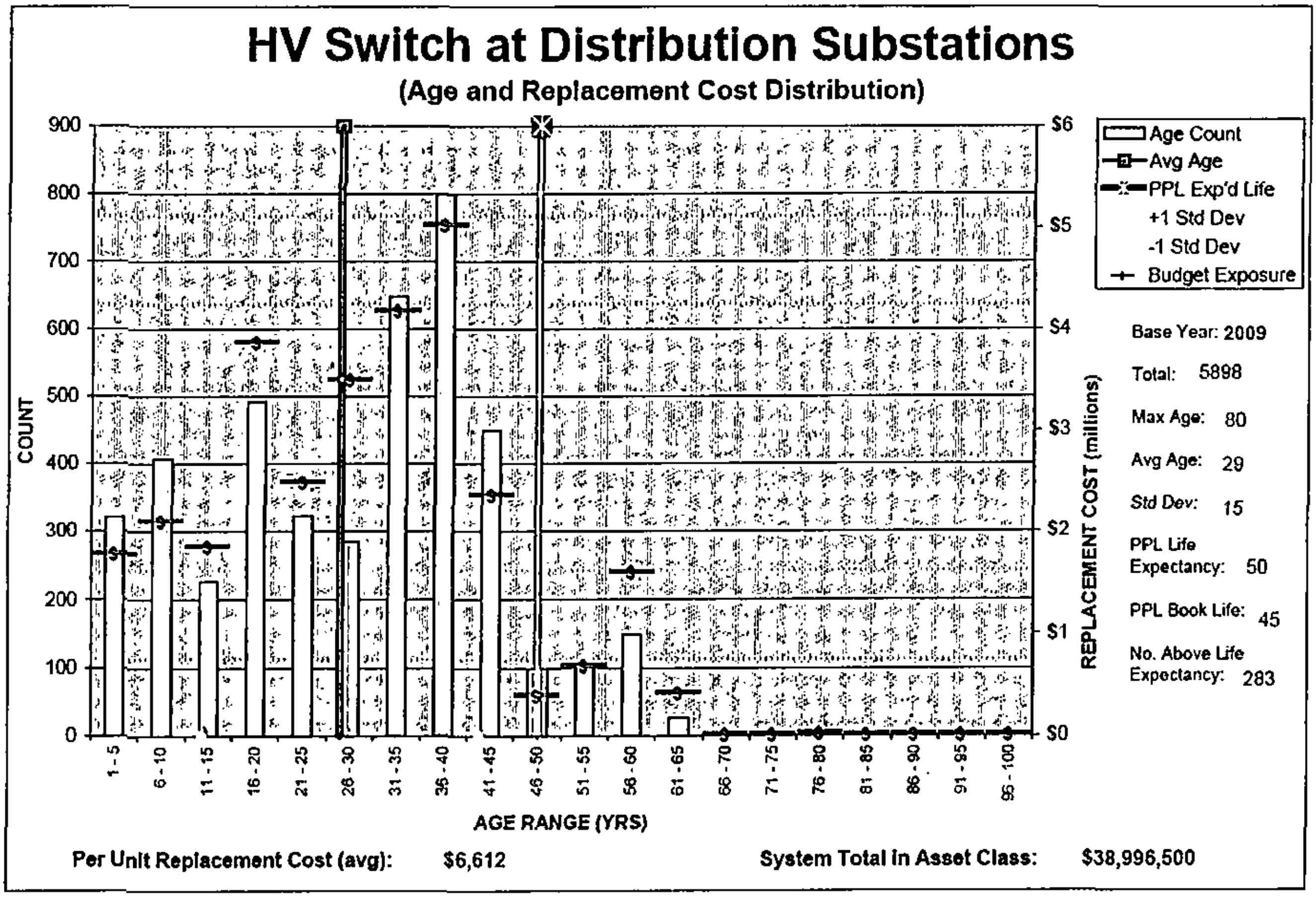


This asset class consists of 312 lead acid batteries and 316 battery chargers; data obtained from Cascade inventory.

The replacement costs noted include the battery or charger purchase price and standard installation costs. The total estimated cost to replace all units which presently exceed life expectancy is approximately $2.9MM. The total estimated cost to replace all units which will reach life expectancy within the next 10 years is about $2MM.



One problematic 138kv BZO oil circuit breaker is presently being replaced at S Allentown Substation in 2008. No additional capital replacements are necessary for this asset class at this time.

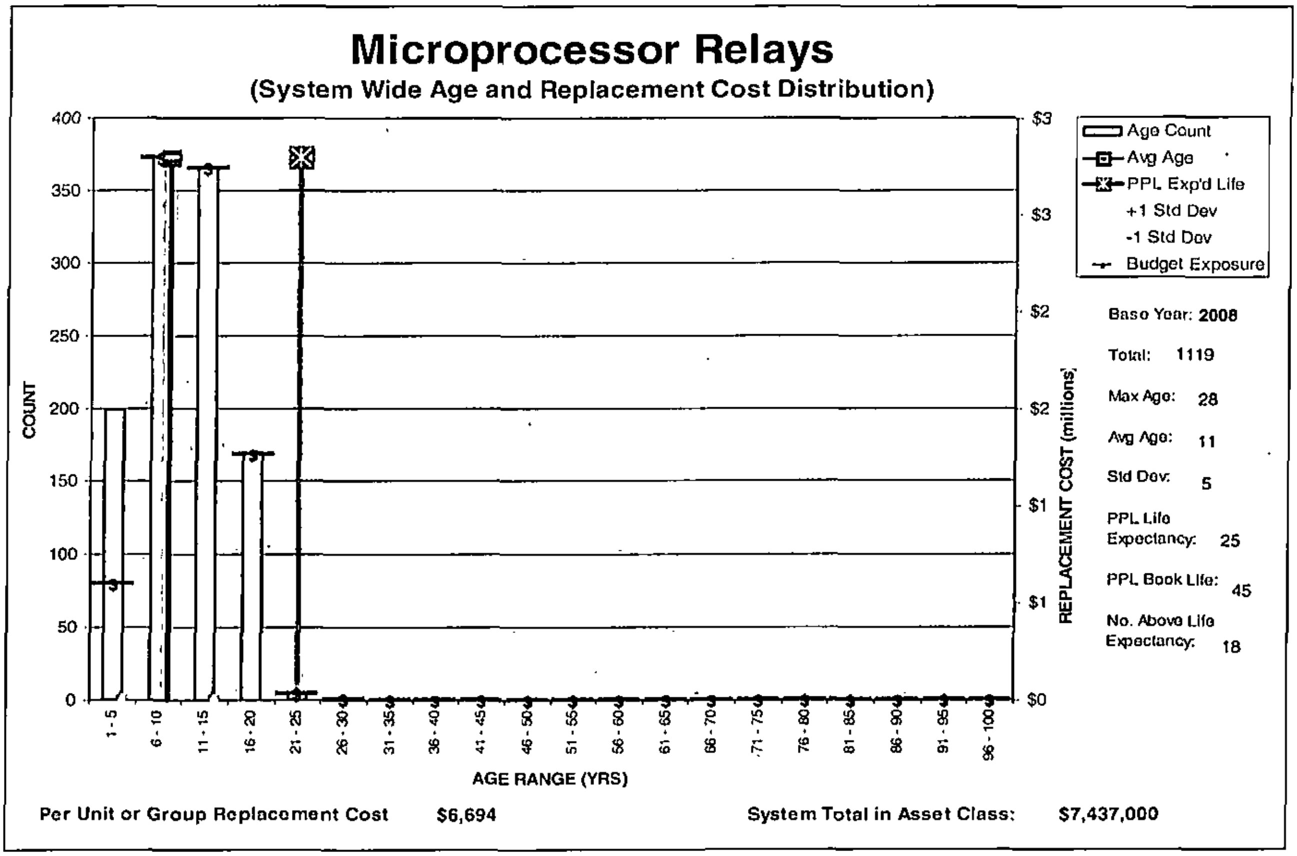


The "High Voltage Switch" asset class consists of the following devices and quantities:

Device	Distribution
Hand-operated, Group-actuated Air/Disconnect Switch	643
Motor-operated, Group-actuated Air/Disconnect Switch	33
Single-pole, Stick-operated Disconnect Switch	5090
Automatic Ground Switch	11
Vacuum Switch	49

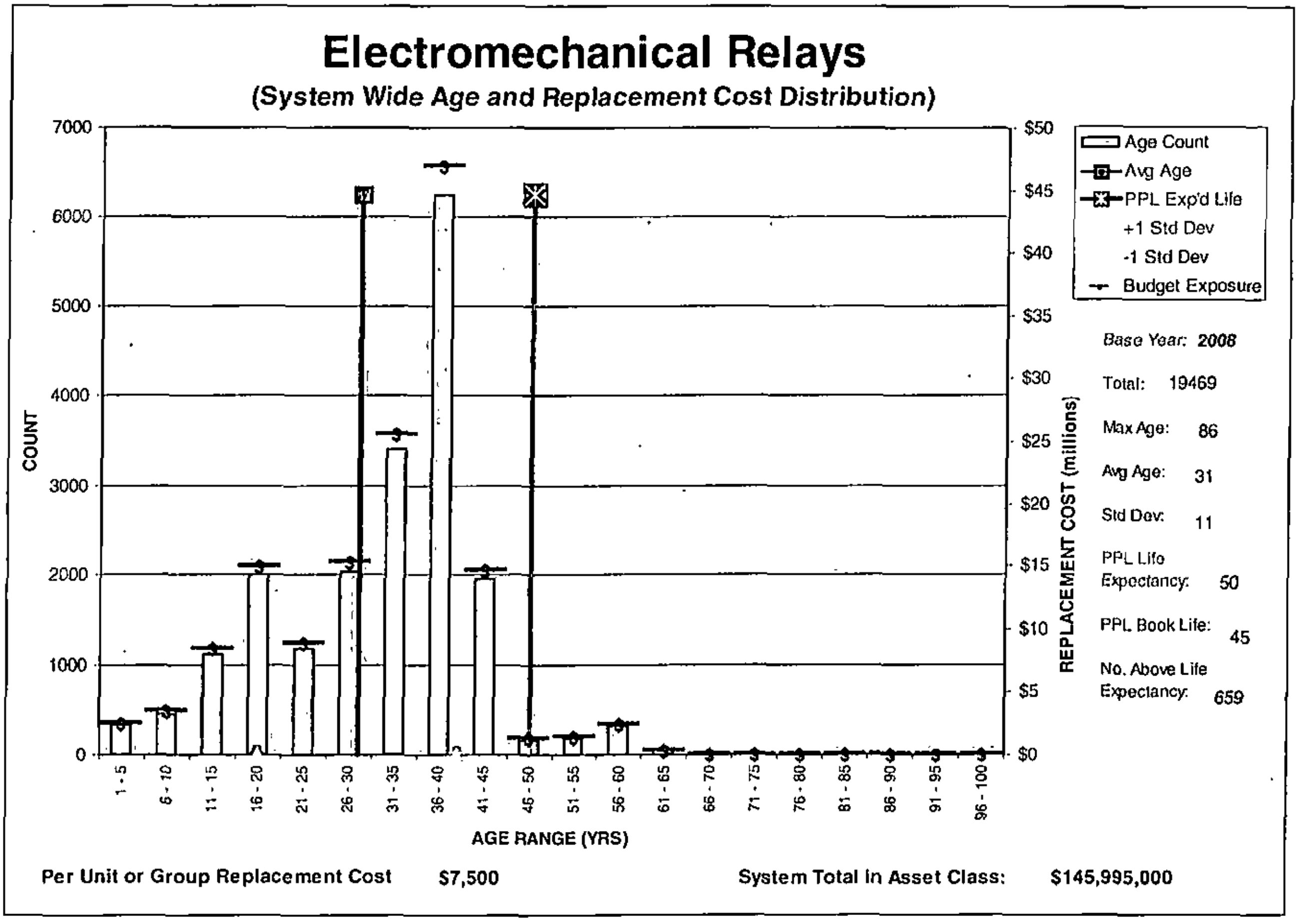
Though the age distribution shows an oncoming wave, many of these devices are single pole- stick operated disconnect switches which the team recommends to run to failure. Hot spot issues uncovered from station thermography are addressed in a timely fashion with appropriate corrective maintenance. No capital replacement *program is recommended for single phase devices however vintage devices with cap* and pin style post insulators will be systematically replaced based upon available funding. Three phase, group operated switches are recommended for annual funding to replace approximately 20 units per year to levelize spending and to replace the asset within its expected life cycle.

4.3.3 Protection & Control



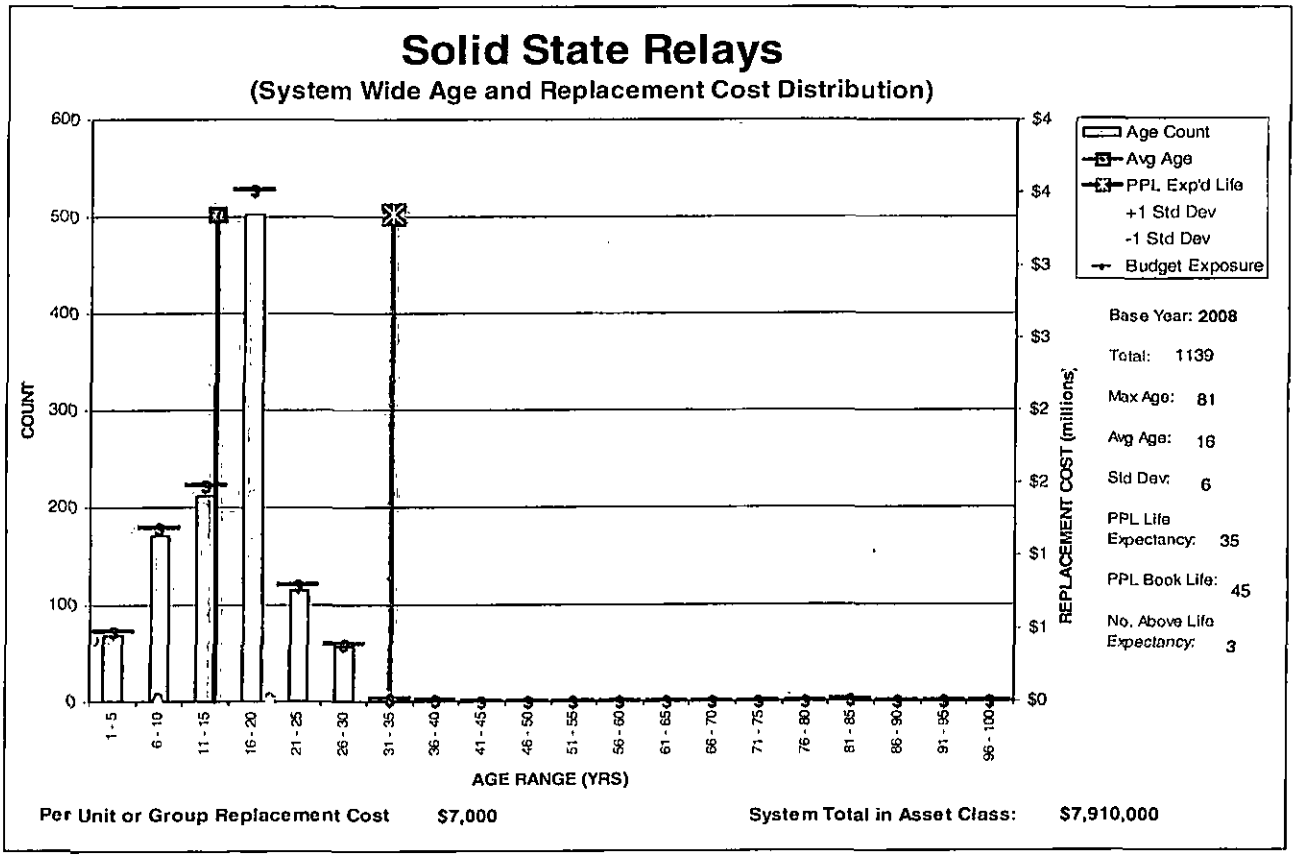
The average age of microprocessor relays in this study is 10 years.
The PPL Expected life is 25 years.
PPLE has 18 units older than expected life.
In 2010 -2015, an additional 115 relays will exceed the expected life.
In 2015 -2020, an additional 715 relays will exceed the expected life.

This asset class consists of 1120 microprocessor relay and relay components such as controller cards, input/output, and magnetic modules. This information was retrieved from the Cascade protection and control database. The replacement costs are based on the present estimated delivered costs for new microprocessor relays, with standard installation costs. The estimated cost to get the maximum age under the PPL expected life and maintain that maximum age in the 2010 to 2020 window is $1.2 MM. Currently, there is $450K per year in the 2010 - 2014 capital budget for DPU-245/445 microprocessor relay replacements.



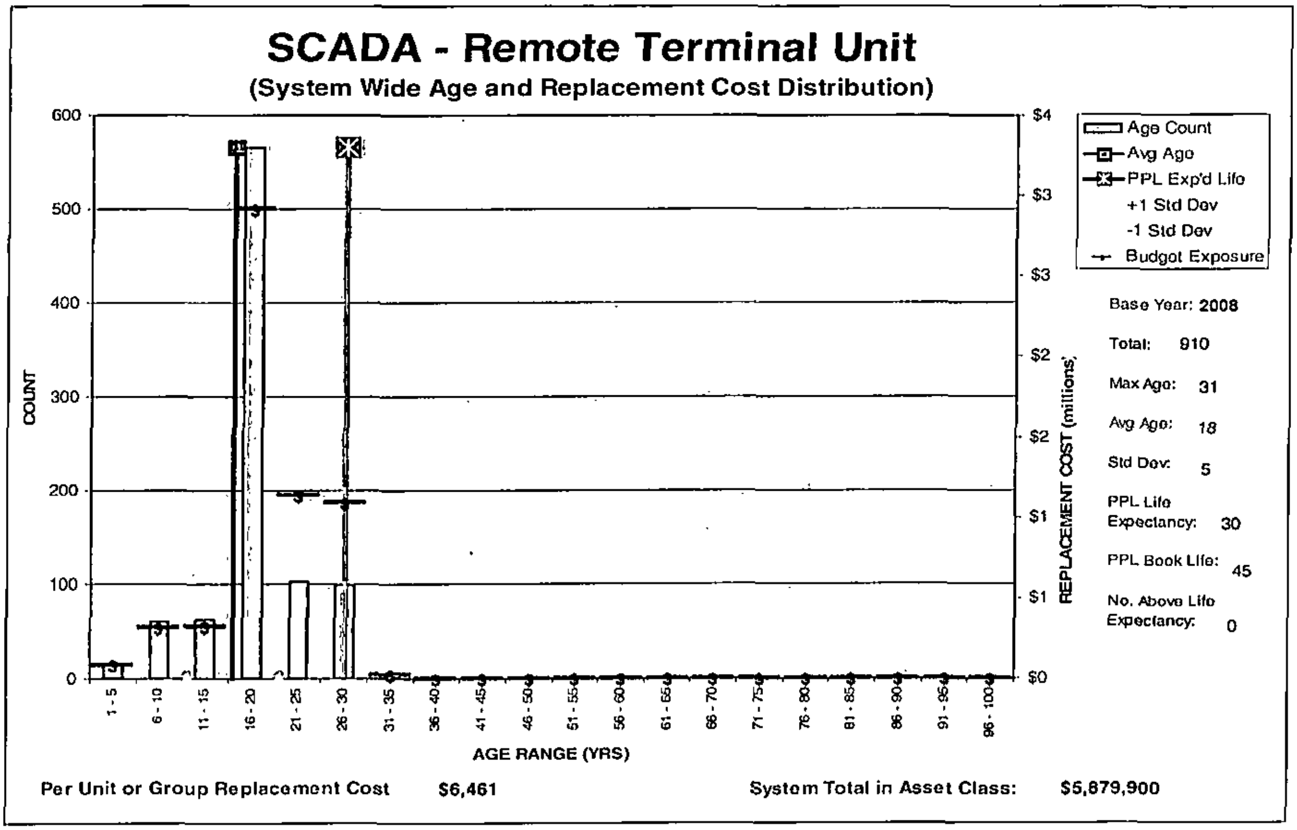
The average age of electromechanical relays in this study is 31 years.
The PPL Expected life is 50 years.
PPLE has 659 relays older than expected life.
In 2010 -2015, an additional 1549 relays will exceed the expected life.
In 2015 -2020, an additional 4727 relays will exceed the expected life.

This asset class consists of 19469 electromechanical relays. This information was retrieved from the Cascade protection and control database. The replacement costs are based on the present estimated delivered costs for new microprocessor relays, with standard installation costs. Due to relay obsolescence, it is likely that microprocessor-based relays will replace existing electromechanical. The estimated cost to get the maximum age under the PPL expected life and maintain that maximum age in the 2010 to 2020 window is $21 MM for the microprocessor-based relays.



The average age of solid-state relays in this study is 15 years.
The PPL Expected life is 35 years.
PPLE has 3 units older than expected life.
In 2010 -2015, an additional 34 relays will exceed the expected life.
In 2015 -2020, an additional 92 relays will exceed the expected life.

This asset class consists of 1139 solid-state relays. This information was retrieved from the Cascade protection and control database. The replacement costs are based on the present estimated delivered costs for new solid-state relays, with standard installation costs. The estimated cost to get the maximum age under the PPL expected life and maintain that maximum age in the 2010 to 2020 window is $450 K.



The average age of a SCADA RTU in this study is 16 years.
The PPL Expected life is 30 years.
PPLE has 0 SCADA RTUs older than expected life.
In 2010 -2015, an additional 52 SCADA RTU devices will exceed the expected life.
In 2015 -2020, an additional 85 SCADA RTU devices will exceed the expected life.

This asset class consists of 910 SCADA RTU devices, including power supplies, transducers, and input/output interface modules. This information was retrieved from the Cascade protection and control database. The replacement costs are based on the present estimated delivered costs for new SCADA RTUs, with standard installation costs. The estimated cost to get the maximum age under the PPL expected life and maintain that maximum age in the 2010 to 2020 window is $6MM. Currently, there is $1MM per year in the 2010 - 2014 capital budget for SCADA RTU replacements.

5 Recommended Maintenance

The existing maintenance plans and the proposed changes in those plans are described for each device group in the MOS database. The costs to do the scheduled activities are projected throughout the 2010 – 2020 time span. The expected costs for the recommended plan scheduled activities are also projected throughout the 2010 – 2020 time span. These costs have been summarized in the tables found in Appendix A.

5.1 Distribution Maintenance Recommendations

Current Plan for Overhead Equipment
The basic equipment for the overhead distribution system is robust and has an expected life span in normal service of 50 years or more. Without formal records for the equipment installed on a particular structure, it is very difficult to determine the manufacturer, model, rating or age of the equipment. Therefore, the equipment has no defined maintenance activities.

Recommended Plan for Overhead Equipment

The recommended formal visual inspection program for the overhead distribution system will identify equipment damage and also detect signs of deterioration. Inspection is the chief means of determining the overhead distribution system's condition and should be considered as the main method to determine a maintenance plan to address deteriorated equipment.

Current Plan for Underground Equipment
Most outages on the underground equipment are due to cable deterioration and subsequent failures. Most others are caused by construction accidents and vandalism. The limited amount of routine testing and monitoring programs currently used on known problematic equipment does provide some information and feedback as to the expected remaining life for the installed underground distribution equipment. The team does not recommend additional changes.

Recommended Plan for All Distribution Equipment

The MOS team recommends replacing certain types of equipment when other work is required on a pole or at an underground location. The specific types of equipment that should be replaced have been noted on the health assessment charts.

We estimate the cost to replace this equipment on a per pole basis to be $550 per average installation. To provide tangible benefits to reliability performance by replacing the equipment [and thereby reducing the number of associated outages]; $2,250,000 per year should be included in the annual budget. The program lifecycle is estimated to be 10 years in length. Replacement of these items on the system while performing other work on a particular pole or at an underground location is an efficient and effective approach. Proactively replacing these items should, over time, *reduce the risk of experiencing unacceptable growth rates in equipment failures* on these circuits, which - if left unmitigated -will negatively impact PPL Electric's reliability performance levels.

Also, we recommend:

1. Use of AMR data to identify overloaded transformers so that they may be replaced prior to failure. and
2. Increased infrared inspections to identify overhead and underground equipment that is operating at abnormally high temperatures (and therefore are prone to failure), so that they may be replaced prior to failure.

5.2 Substation Maintenance Optimization

Prior to this initiative, the maintenance philosophy for substation physical/electrical equipment has largely been one of time-based activities with occasional, more frequent condition-based testing/monitoring when routine inspections and tests identify deteriorated conditions, problems or areas of concern. The goals of the optimized maintenance strategy presented here are:

- continuation of time-based maintenance activities and procedures deemed worthwhile in terms of the quality of the testing results or evidence of their need,
- elimination of certain time-based maintenance activities or procedures which have proven to be of little to no value (in assuring continuous, correct device performance) or have inconsistent measure (e.g.: 12kv CB trip testing),
- creation of new time-based maintenance activities and procedures which are expected to improve device performance (e.g.: "modified clean & lube" process for 12kv CBs to minimize failures to trip/close),
- change to the frequency of certain existing time-based maintenance activities and procedures (mostly in a more frequent direction) believed to provide important data for accurate, ongoing device health assessment (e.g.: Doble, DGA and oil dielectric testing, etc.) and,
- creation of new operations-based maintenance activities and procedures which apply manufacturer's recommended guidance for maintenance overview (e.g.: transformer TCUL and certain HV CB overhauls, etc.)

It is recognized that increased maintenance (by number of applied activities and procedures) and shortened frequencies of certain activities will not necessarily extend the lifetime of any specific in-service equipment. However, in doing so in certain situations, the process will provide more data by which equipment condition can be trended and failure predicted as opposed to mere reaction when it does fail. Having the capability to more accurately assess and react to a downturn in the performance of equipment will significantly help system reliability metrics and reduce *exposure the outcome of violent equipment failures has on collateral damage and personnel safety.*

5.3 Protection and Control Maintenance Recommendation

The objective of the protection and control maintenance and testing program is to ensure the integrity of the power delivery system by reactively correcting real-time equipment problems and by using experience, performance records, and historical data to proactively anticipate future potential problems.

Even under normal conditions, electrical, mechanical, thermal, and environmental stresses are continually at work predictably degrading relay performance. An effective maintenance program shall ensure that the electrical power system protection system will respond to abnormal conditions as designed despite these stresses. Key elements of the maintenance and testing program shall include the following:

- Maintaining each relay in a state of readiness as determined by an acceptable *level of reliability.*
- Demonstrating compliance with applicable regulatory and industry requirements.
- Demonstrating that each relay and protection system can fulfill its design basis function.
- Providing performance trending information for assessing the program effectiveness and for anticipating future performance problems.

The purpose of preventive maintenance is to reduce the probability of failures by examining equipment to assess and address deficiencies before failure or significant degradation can occur. In economic terms, this translates into trying to avoid the indefinable costs of corrective maintenance made necessary by unanticipated deficiencies and the potentially even larger costs of failures that occur while the equipment is in-service.

The *goals of the recommended maintenance strategy presented here are:*

- Continuation of time-based maintenance activities and procedures deemed worthwhile in terms of the diagnostic value of the testing results or evidence of their need.
- Use of computer-driven test equipment and software with standard test plans to test all relays.
- Focus preventive maintenance on components that would most benefit from more frequent or more intensive maintenance, including those with a high potential impact on the power system, those with a history of settable

parameter drift or degradation over time, and those with known performance or reliability deficiencies.

- Changes in the frequency of certain existing time-based maintenance activities and procedures.

- Identification of components that should be replaced rather than be subjected to the more frequent and intensive maintenance efforts that drain resources away from more productive activities.

Performing periodic maintenance based solely on generalized time intervals makes it impossible to economically and strategically optimize testing resources because calendar-mandated maintenance periods do not necessarily take into account equipment condition, history, and in-service performance.

Modern microprocessor-based relays have self-monitoring capabilities that allow relay performance to be sufficiently verified with minimal on-site periodic testing. These capabilities include real-time monitoring of the relay's hardware and software health, and event monitoring that logs the relay's dynamic performance during actual power system disturbances. Test personnel can review event logs to assess whether individual relay elements responded correctly and within their setting parameters, and whether the integrated relay system provided an overall appropriate response.

On the other hand, devices of electromechanical or solid-state design offer no means of self-monitoring. Some of these devices have historically required more frequent maintenance than the minimum eight (8) years as defined by the current maintenance plan. The recommended maintenance plan will evaluate the criticality, health, failure rate, and monitoring capability of each device and adjust the test intervals accordingly, with sound technical and financial justification, to maintain the highest degree of reliability.

Experience and performance history have shown that certain relays require additional maintenance to reduce the probability of failure or degraded performance. Failure of a distribution system relay can have a significant negative impact on the safety and reliability of the distribution system. Relays, such as the ABB DPU-245/445, have known technical issues documented with applicable manufacturer service advisories. Furthermore, relays in this category are usually difficult to maintain given their age, lack of spare parts, and overall condition. The team recommends changing the test interval from eight (8) years to a four (4) year test interval for certain first generation microprocessor, electromechanical overcurrent and reclosing relays. The ABB relays noted here, and others as well, are included as part of the capital replacement strategy. Until all designated problematic assets are replaced, it is expected that an additional $300K per year is required to provide adequate maintenance and testing of these devices to ensure continued reliable operation.

Protection and control engineers are developing automated test plans to streamline acceptance and periodic testing of complex electromechanical and microprocessor-based relay schemes. The initial investment to purchase additional test equipment and develop automated test plans is $500K over the next two years. This initial *investment will have long-term benefits, including the development of standardized* test methods that save testing time, provide consistent results, and generate electronic records which are readily available for regulatory review. Corollary benefits of automated test plans and electronic records include making it easier for regional test crews to share test plans and "best practices" for testing; providing opportunities to update, standardize, and centrally store our extensive library of test procedures, many of which presently exist in various places and in various formats; and ultimately replacing hand written relay record cards with more detailed and more durable electronic test reports.

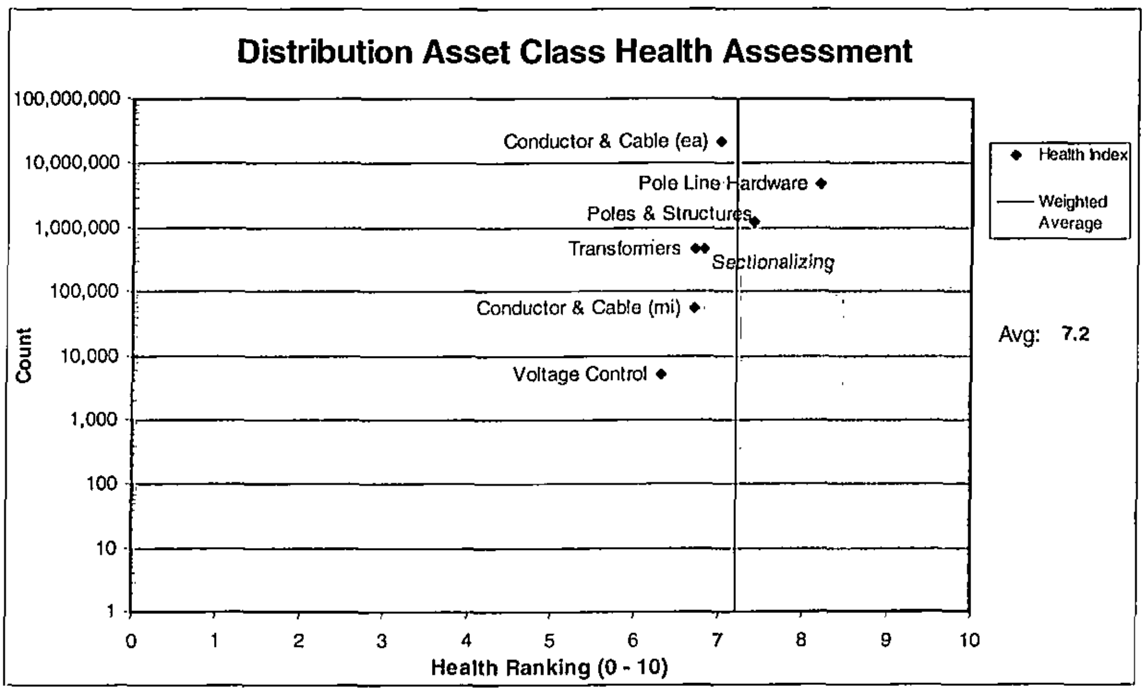
It is recognized that increased maintenance (as measured by the number of maintenance activities or the extent of maintenance procedures) performed with greater frequency will not necessarily extend the lifetime of in-service equipment. For certain classes of equipment, maintenance can be counter-productive. This was demonstrated by the intensive periodic SCADA RTU testing done during the 1970's through early 1990's by the former Computer Maintenance group. Repetitive removal and reinstallation of circuit cards created wear in the spring-loaded card sockets, eventually reducing their ability to effectively grasp the circuit card connectors. This created RTU failures and malfunctions that could require significant time and resources to find and repair. This maintenance was done with the best of intentions, but it invariably transformed solidly functioning SCADA RTUs into systems with reduced reliability and availability, sometimes for considerable periods of time after the maintenance was done. The existing SCADA maintenance plan began with recognition that the health of SCADA RTUs is constantly monitored via communication with the Transmission Management System. When a SCADA RTU fails, corrective maintenance is performed. Significant improvement to the reliability and availability of even the most troublesome SCADA RTUs was observed after changing maintenance practices to this condition-based approach.

6 Equipment Class Details

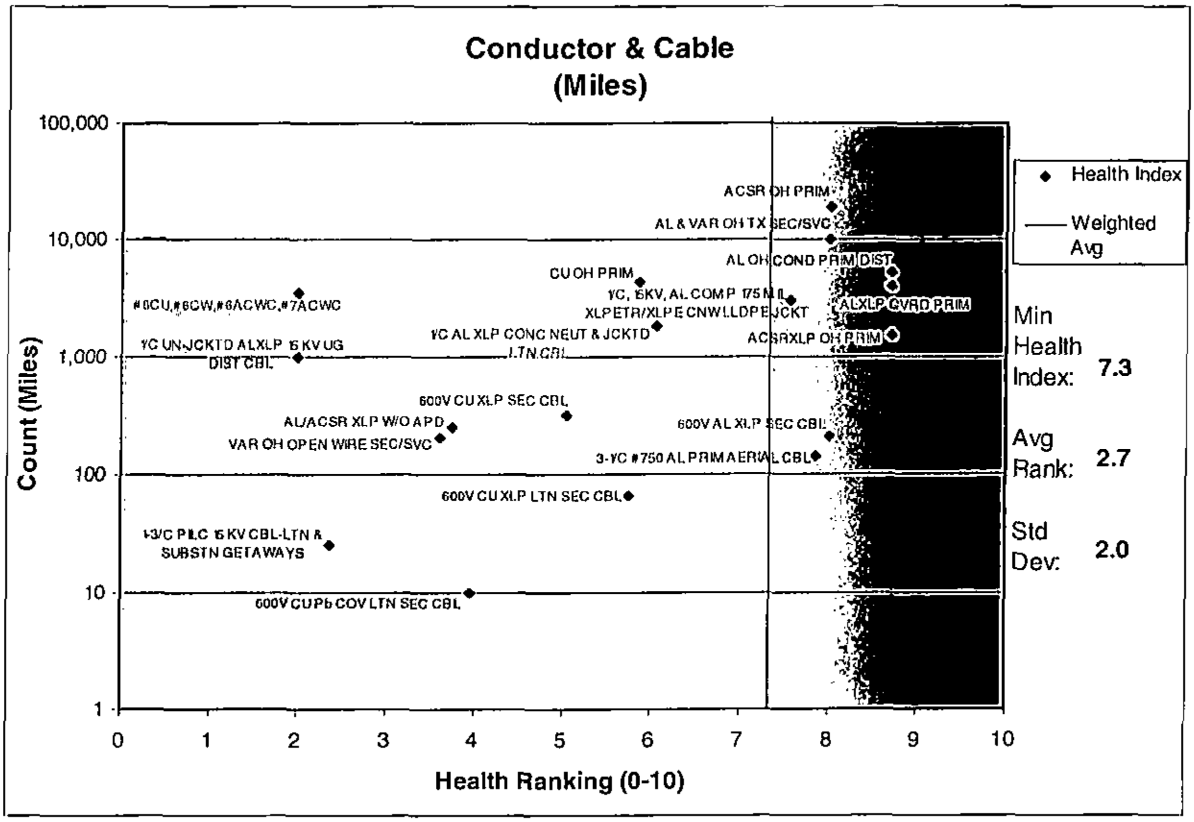
Since PPL performed condition assessments at a high level, the health indices produced represent the average condition of the equipment on the PPLE system for each asset classification. The information in this section identifies the asset components to the equipment class level and provides the individual health assessment of each equipment class. This provides a means to understand which equipment within an asset class is driving the poor or marginal numbers. The graphs provided portray the quantity of each equipment class and the condition rating for that equipment. *The rating system that ties these ratings to the asset class graphs is* as follows:

- 0-2 Poor
- 2-4 Marginal
- 5-6 Good
- 7-8 Very Good
- 9-10 Excellent

6.1 12 kV Distribution Equipment



The chart for the overall health assessment of the asset classes for distribution displays a weighted average of 7.2. Although the overall health is shown as very good, there are specific equipment items in each asset class where capital and/or maintenance programs could be developed for further improvement. The following charts break down each asset class and break out the corresponding lowest health ratings.



The items with lower Health Rankings in the Conductor & Cable class by mileage are:

- 1-3/C PILC 15 kV Cable – LTN and Substation Getaways (2.35 rating HI, # 25 miles)
  - Equipment Class: Primary cable
  - Failure Mode: Fails to provide the proper insulation level and continuous AC path.
  - Failure Impact: Possible customer outages.
  - Maintenance Optimization: Run to replacement – the age of the cable in the field indicates a concern and the need for a formalized maintenance program.
  - Capital Replacement: Replace 5 miles per year. Assume capital cost is $500,000/mile and expense is $30,000/mile.
- Aluminum Overhead Conductor for Primary Distribution (2.4 HI, # 5,200 miles)
  - Equipment Class: Conductor
  - Failure Mode: Mechanical and electrical failures due to corrosion and loss of tensile strength (annealing).
  - Failure Impact: Conductor failure results in many customers out of service due to the loss of load carrying capabilities. A live downed conductor also presents serious safety concerns for workers and the general public.

- Maintenance Optimization: Run to replacement – the majority of the failures occur due to damage, not deterioration. Severe weather conditions, contact with trees, vehicles, construction accidents, animals, and vandalism are the major causes of failure. Load growth and relocations due to agency requests requires this equipment to be replaced prior to the deterioration and end of life.
- Capital Replacement: None
- Wire Size #6 (Cu), #6 (Cu Weld – CW), #6A (Cu Weld Cu – CWC), & #7A (Cu Weld Cu – CWC) Copperweld (CW) conductor is a steel strand with a copper coating. (2.0 HI, # 3,500 miles) Copperweld Copper (CWC) has both copperweld and solid copper strands.
- Equipment Class: Conductor
- Failure Mode: Mechanical and electrical failures due to corrosion and loss of tensile strength (annealing).
- Failure Impact: Conductor failure results in many customers out of service due to the loss of load carrying capabilities. In addition, a live downed conductor presents serious safety concerns for workers and the general public.
- Maintenance Optimization: Run to replacement – the majority of the failures occur due to damage and deterioration. Annealing, severe weather conditions, and contact with trees are the major causes of failure.
- Capital Replacement: Replace 35 miles per year (system). Assume capital cost is $250,000/mile and expense is $30,000/mile (2008 dollars). Given this rate, we will replace all of the conductor on circuits with the highest historical contributions to Customers with Multiple Interruptions (CMI) and will improve the circuit health and resultant reliability performance throughout the next 20 years.
-

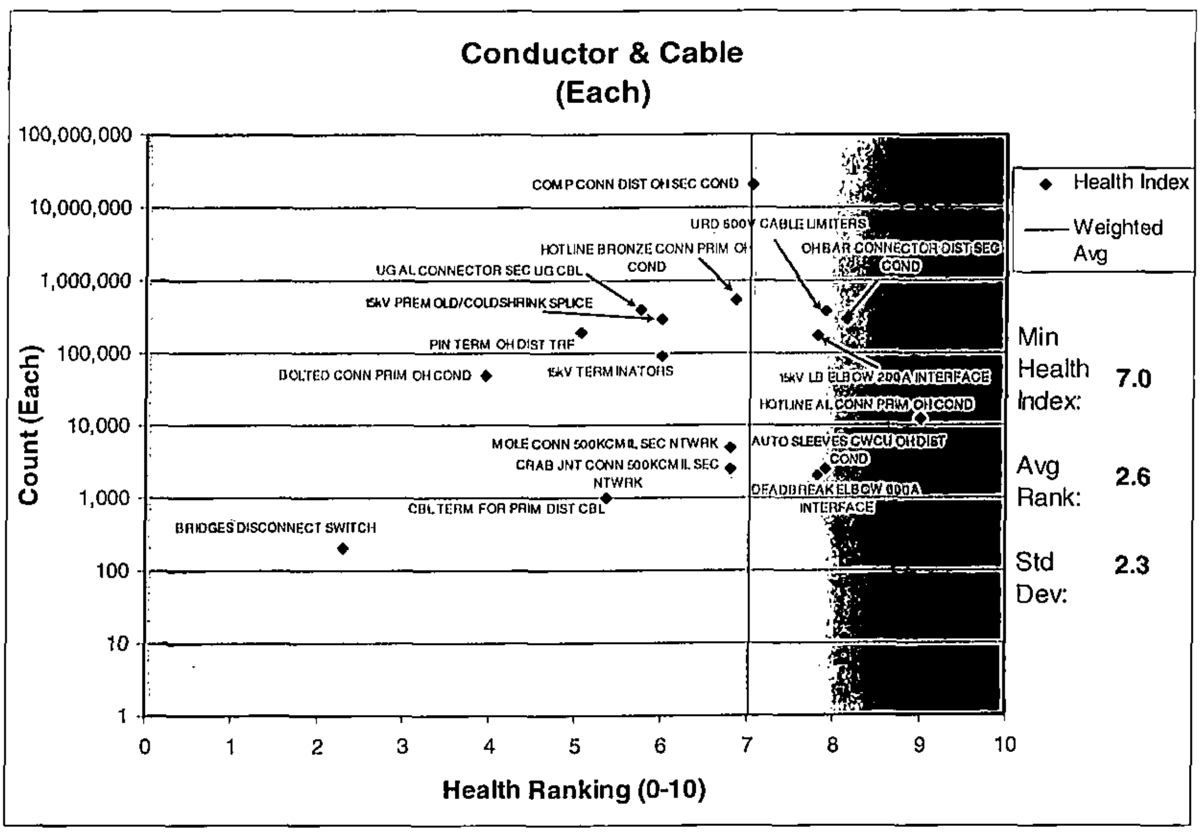
- 1/C Un-Jacketed Al XLP 15 kV Underground Distribution Cable (2.0 HI, # 1,000 miles)
  - Equipment Class: Primary cable
  - *Failure Mode: Fails to provide proper insulation level and continuous* AC and path to ground. Reduced or inadequate return for neutral current.
  - Failure Impact: Customers are out of service and possible shock concerns to the general public.
  - Maintenance Optimization: Continue to use existing maintenance plan -- Based on the number of failures of the cable sections, perform a TDR, power factor or tan delta test and a PD test. Record the data and issue recommendations for replacement, cable cure or no action required.
  - Capital Replacement: None required.
- *Al/ACSR XLP without APDs (3.75 HI, # 250 miles)*
  - Equipment Class: Conductor
  - Failure Mode: Mechanical and electrical failures due to corrosion and loss of tensile strength (annealing).
  - Failure Impact: Conductor failure results in many customers out of service due to the loss of load carrying capabilities. In addition, a live

downed conductor presents serious safety concerns for workers and the general public.

- o *Maintenance Optimization:* Line inspections should provide data as to locations where the XLP conductor does not have APDs installed. APDs should be installed on the entire circuit to eliminate lightning concerns. In addition, crews should install APDs when working on the pole.
- o Capital Replacement: None

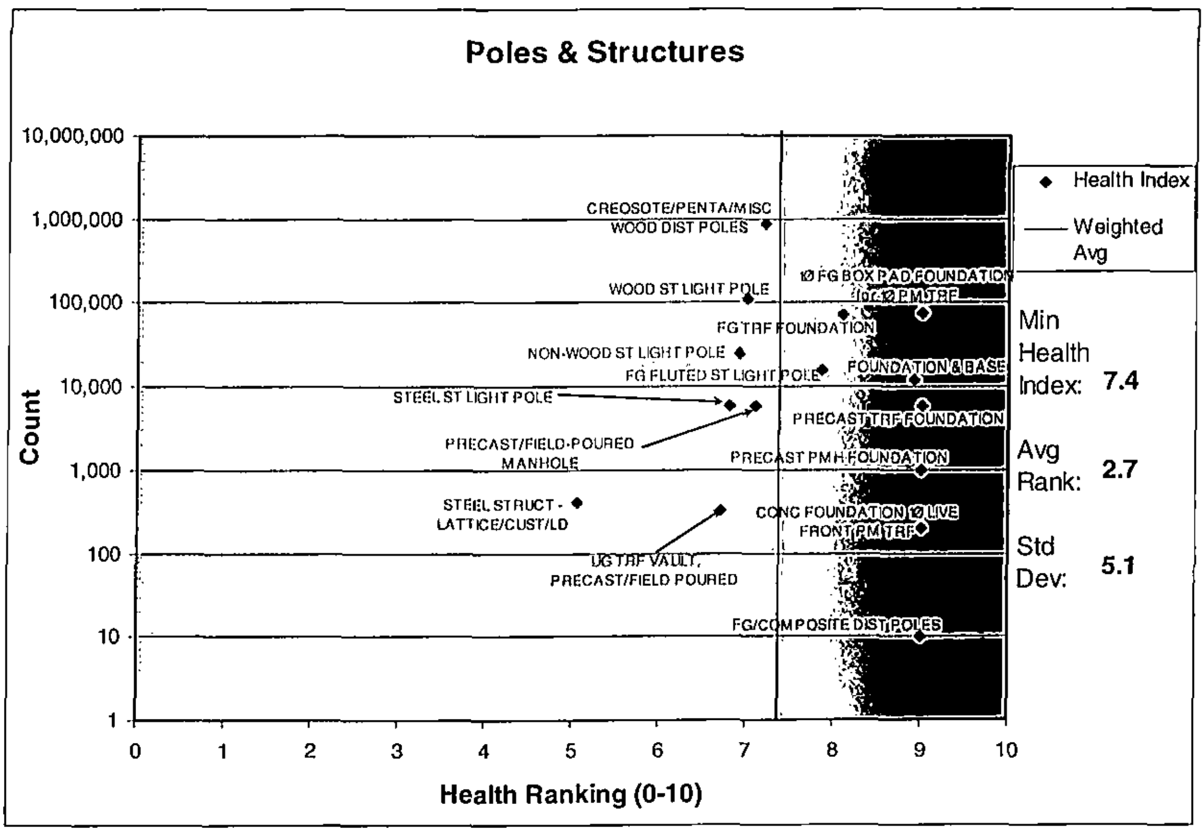
o Various Sizes and Types of Overhead Open Wire Secondary/Services (3.6 HI, # 200 miles)

- o Equipment Class: Conductor
- o Failure Mode: Mechanical and electrical failures due to corrosion and *loss of tensile strength (annealing).*
- o Failure Impact: Conductor failure results in several customers out of service due to the loss of load carrying capabilities. A live downed conductor also presents serious safety concerns for workers and the general public.
- o Maintenance Optimization: Run to replacement – the majority of the failures occur due to damage, not deterioration. Severe weather conditions, contact with trees, vehicles, construction accidents, animals, and vandalism are the major causes of failure. Load growth and relocations due to agency requests requires this equipment to be *replaced prior to the deterioration and end of life.*
- o Capital Replacement: None

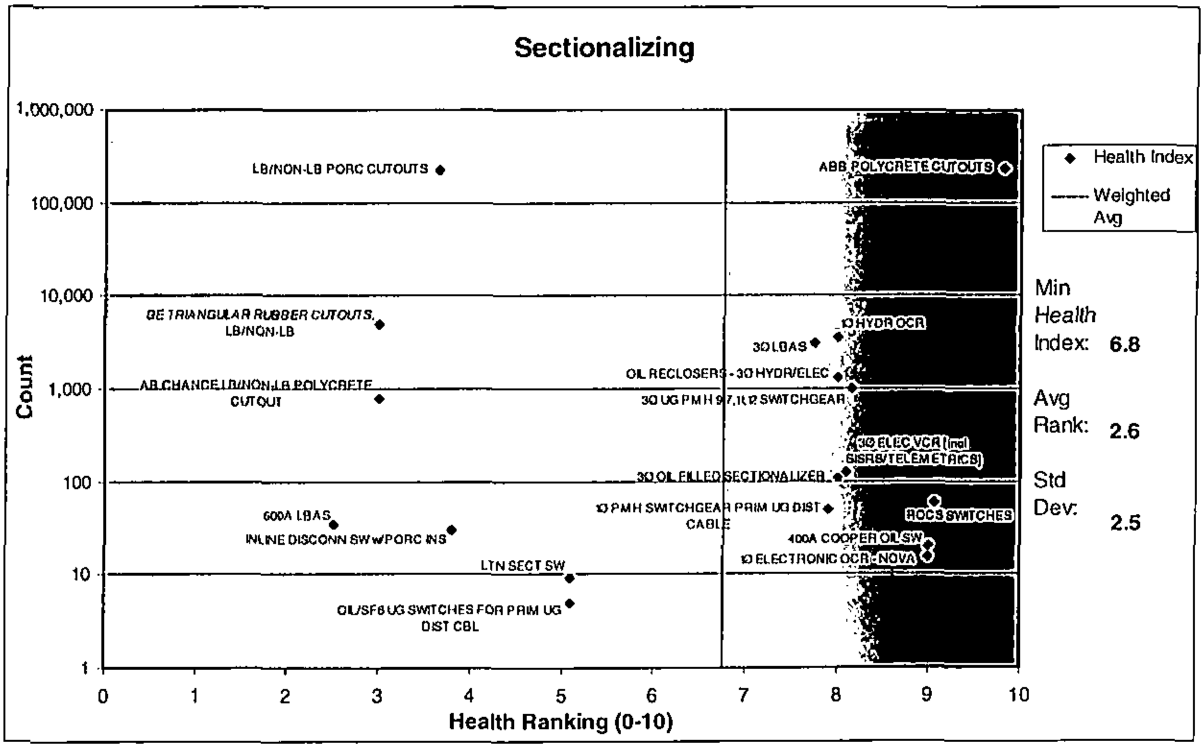


Items with lower health rankings of the Conductor & Cable class by each unit are:

- Bridges Disconnect Switch (2.3 HI, # 200)
  - Equipment Class: Connectors
  - Failure Mode: Mechanical or electrical failure causes an open circuit.
  - Failure Impact: Generally, loss of service to the customers on the entire distribution line.
  - Maintenance Optimization: Run to replacement – the majority of the failures occur due to deterioration. The thermovision program helps to identify potential failures.
  - Capital Replacement: Use local knowledge to identify locations and replace all units by 2012.
- Bolted Connectors for Primary Overhead Conductor (3.95 HI, # 50,000)
  - Equipment Class: Connectors
  - Failure Mode: Mechanical or electrical failure causes an open circuit.
  - Failure Impact: Loss of service to the customer
  - Maintenance Optimization: Run to replacement – the majority of the failures occur due to deterioration. Severe weather conditions, contact with trees, vehicles, and construction accidents are also causes of failure. In addition, the present thermovision inspection helps to identify potential failures.
  - Capital Replacement: None



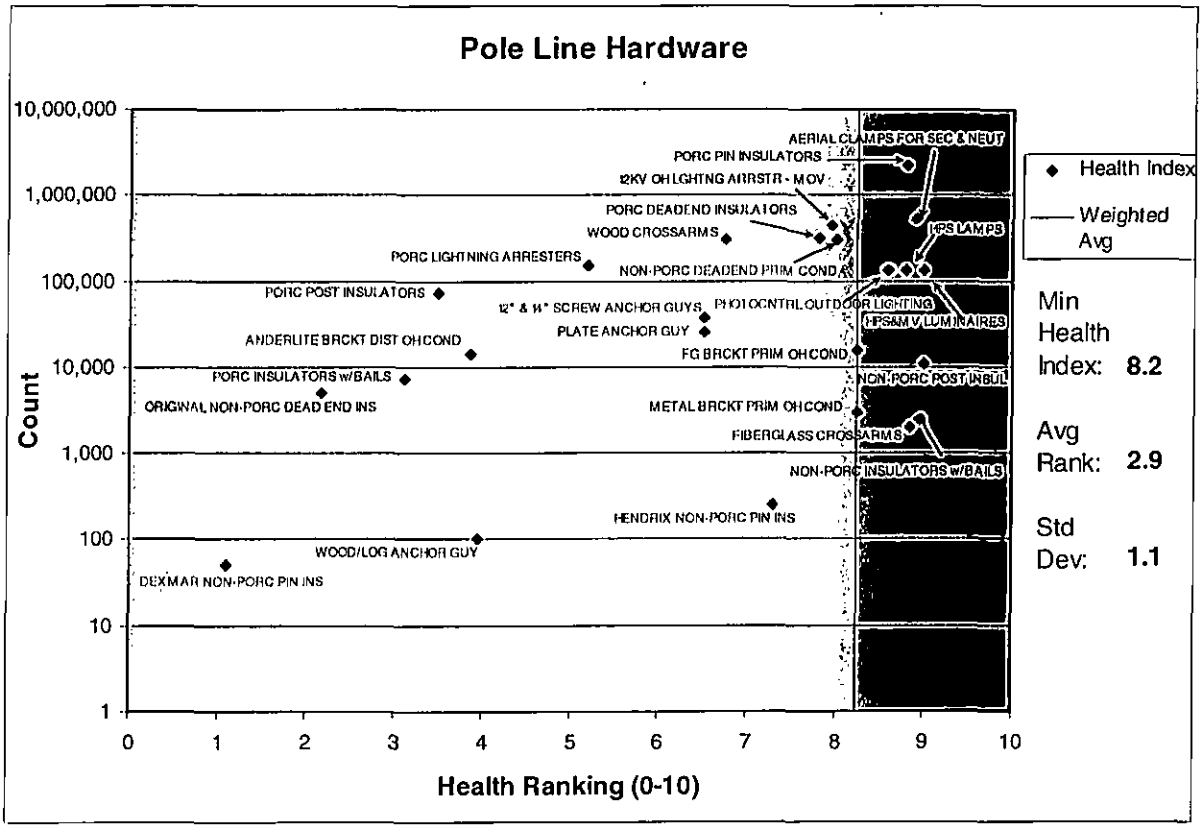
Based upon the health assessment, routine inspections need to be continued and documented.



Sectionalizing class items with low health rankings include the following:

- AB Chance and Westinghouse 600A Loadbreak Air Switch (2.5 HI, # 35)
  - Equipment Class: Switches
  - Failure Mode: The switch will not open or close properly. Animals can also cause the switch to fail electrically.
  - Failure Impact: Customers are out of service and sectionalizing is not available.
  - Maintenance Optimization: Replace when found following the present 10-year maintenance plan.
  - Capital Replacement: None
- AB Chance Loadbreak and Non-Loadbreak Polymer Concrete Cutout (3 HI, # 800)
  - Equipment Class: Switches
  - Failure Mode: Electrical failure causing tracking.
  - Failure Impact: Possible pole fire and customer interruptions.
  - Maintenance Optimization: Replace when working on the pole.
  - Capital Replacement: None
- GE Triangular Loadbreak and Non-Loadbreak Rubber Cutout (3 HI, # 5,000)
  - Equipment Class: Switches
  - Failure Mode: Mechanical and electrical failures causing the loss of insulation.
  - Failure Impact: Possible pole fire and customer interruptions.
  - Maintenance Optimization: Replace when working on the pole.
  - Capital Replacement: None
- Loadbreak and Non-Loadbreak Porcelain Cutouts (3.65 HI, # 220,000)
  - Equipment Class: Switches

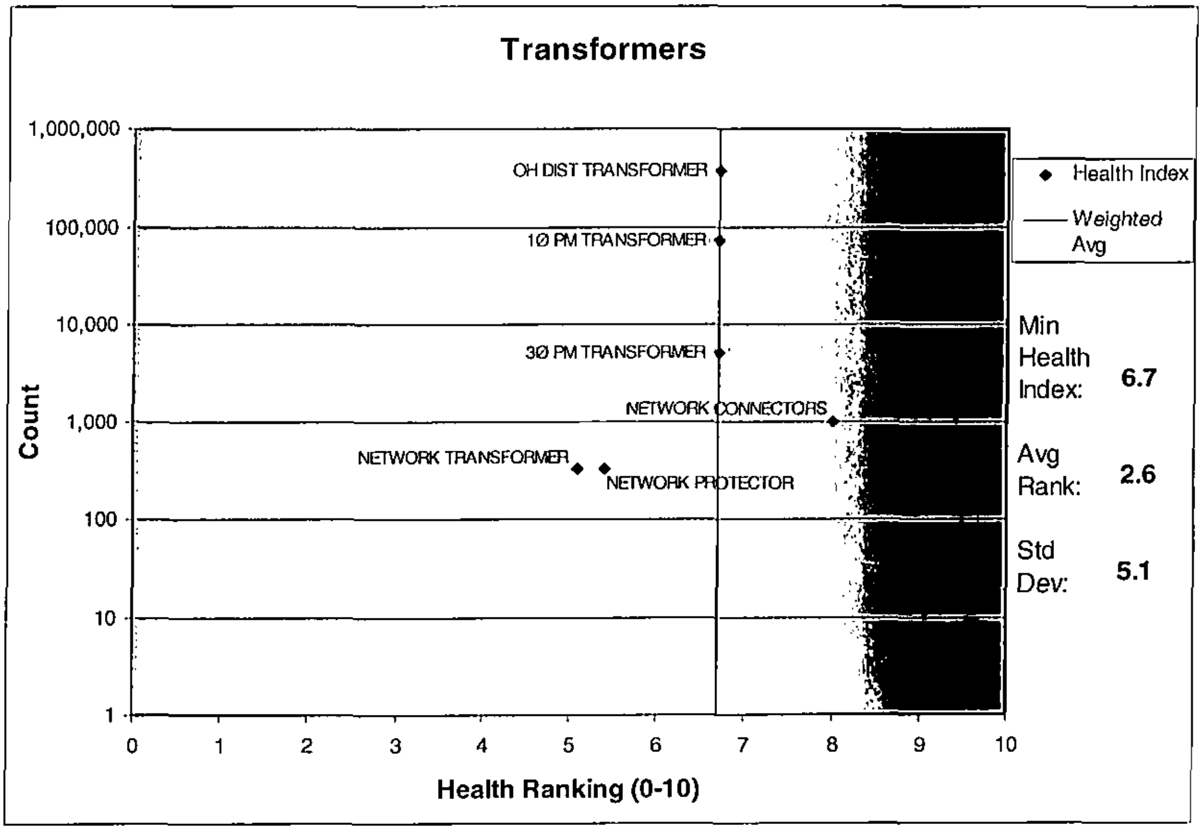
- Failure Mode: Mechanical and electrical failures causing the loss of insulation.
- Failure Impact: Possible pole fire and customer interruptions.
- Maintenance Optimization: Replace when working on the pole.
- Capital Replacement: None



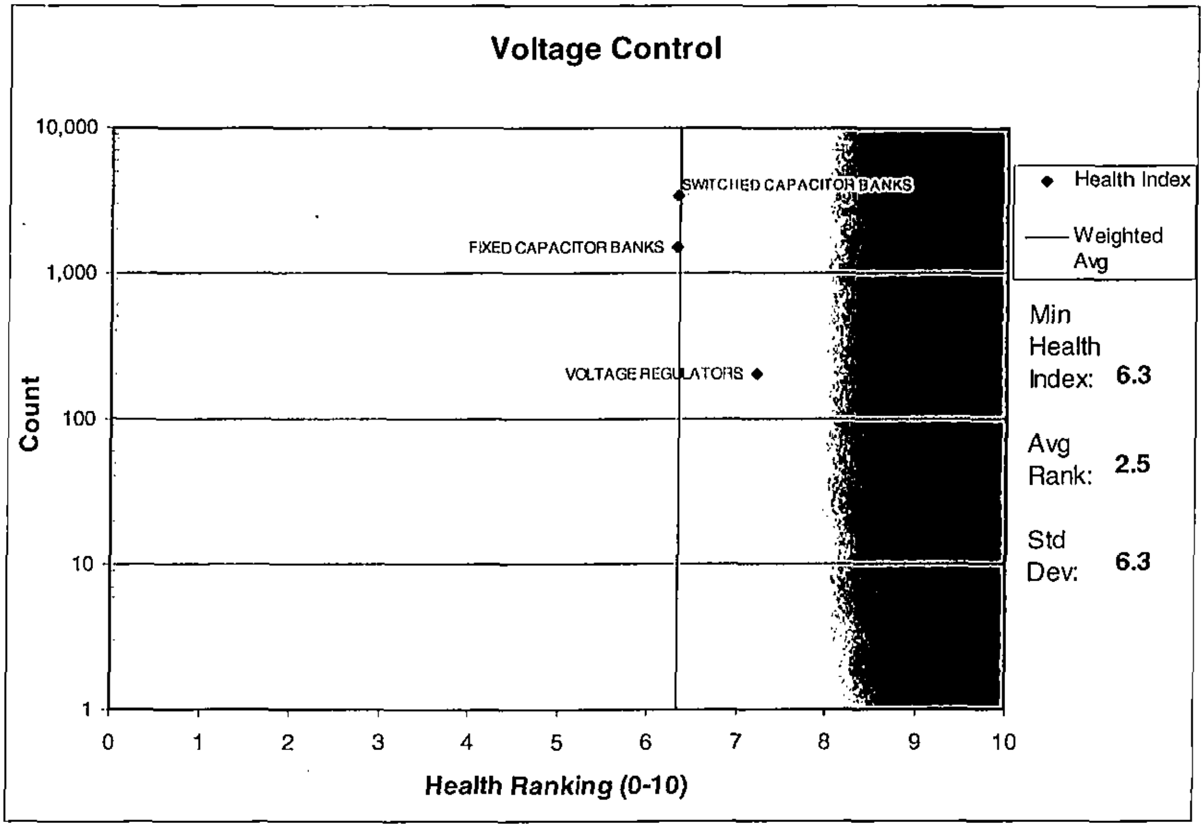
Items in the Pole Line Hardware class with low health rankings include:

- Dexmar Non-Porcelain Pin Insulators (1.1 HI, # 50)
  - Equipment Class: Insulators
  - Failure Mode: Electrical failures causing loss of insulation.
  - Failure Impact: Pole fires and customer interruptions.
  - Maintenance Optimization: Include in line inspection reports to identify locations where this equipment is installed. Also, replace when working on a pole.
  - Capital Replacement: None
- Original (Permali, Locke) Non-Porcelain Dead End Insulators (2.15 HI, # 5,000)
  - Equipment Class: Insulators
  - Failure Mode: Mechanical and electrical failures resulting in the inability to provide proper insulation levels.
  - *Failure Impact: Pole fires and customer interruptions.*
  - Maintenance Optimization: Include in line inspection reports to identify locations where this equipment is installed. Also, replace when working on a pole.
  - Capital Replacement: None

- Porcelain Insulators with Bails (3.1 HI, # 7,500)
  - Equipment Class: Insulators
  - Failure Mode: Mechanical failures causing the inability to provide proper support and insulation levels.
  - Failure Impact: Possible tracking, pole fires, and customer interruptions.
  - Maintenance Optimization: Replace during OCR maintenance or other work occurring on the pole.
  - Capital Replacement: None
- Porcelain Post Insulators (3.5,72000)
  - Equipment Class: Insulators
  - *Failure Mode: Mechanical and electrical failures, the equipment cracks and causes tracking.*
  - Failure Impact: Possible tracking, downed conductor, and customer interruptions.
  - Maintenance Optimization: Include in line inspection reports to identify locations where this equipment is installed. Also, replace when working on a pole.
  - Capital Replacement: None
- Anderlite Bracket for Distribution Overhead Conductor (3.85 HI, # 14,000)
  - Equipment Class: Insulators
  - Failure Mode: Mechanical failures causing the inability to provide proper support and insulation levels.
  - Failure Impact: Possible downed conductor and customer interruptions.
  - Maintenance Optimization: Replace when working on a pole.
  - Capital Replacement: None

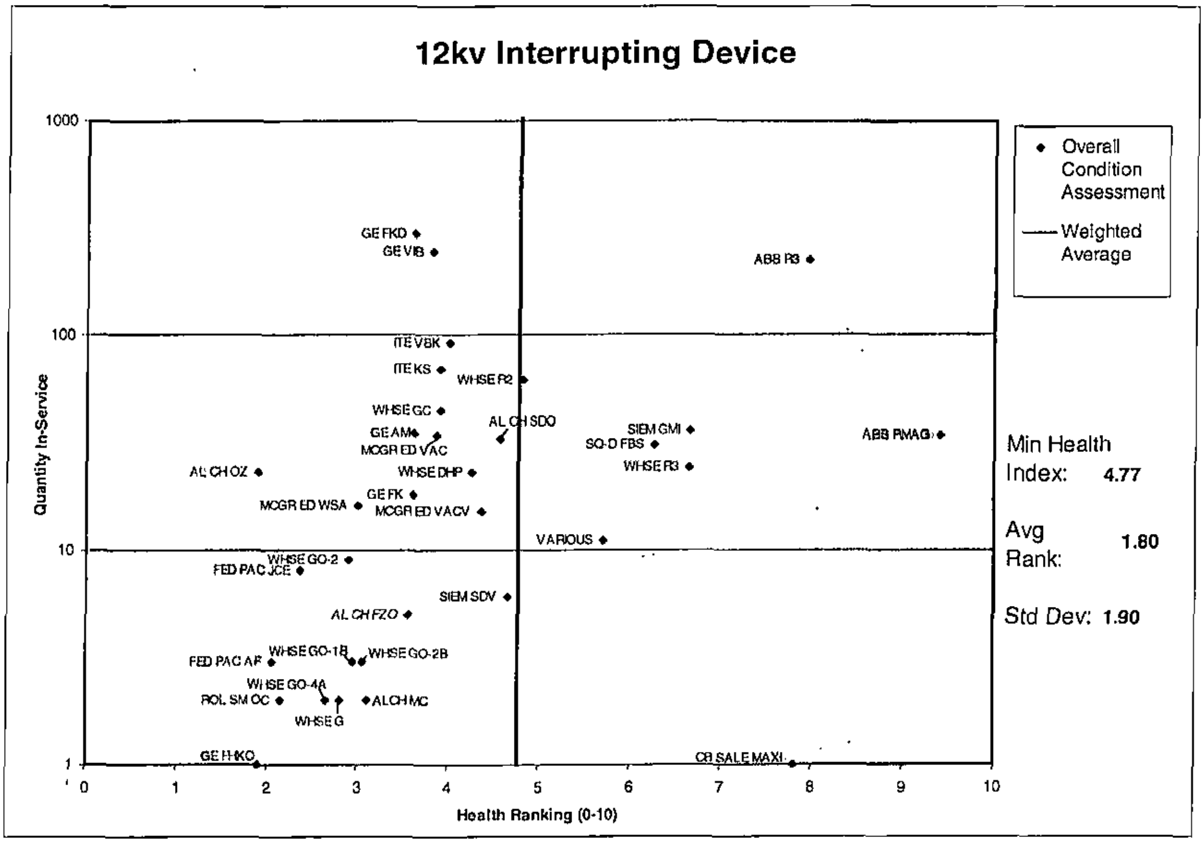


As data is currently available for network transformers and network protectors, they should be replaced as dictated by condition inspections or when a 50-year age is reached.



Based upon the health assessment for voltage control equipment, the current maintenance programs should be continued.

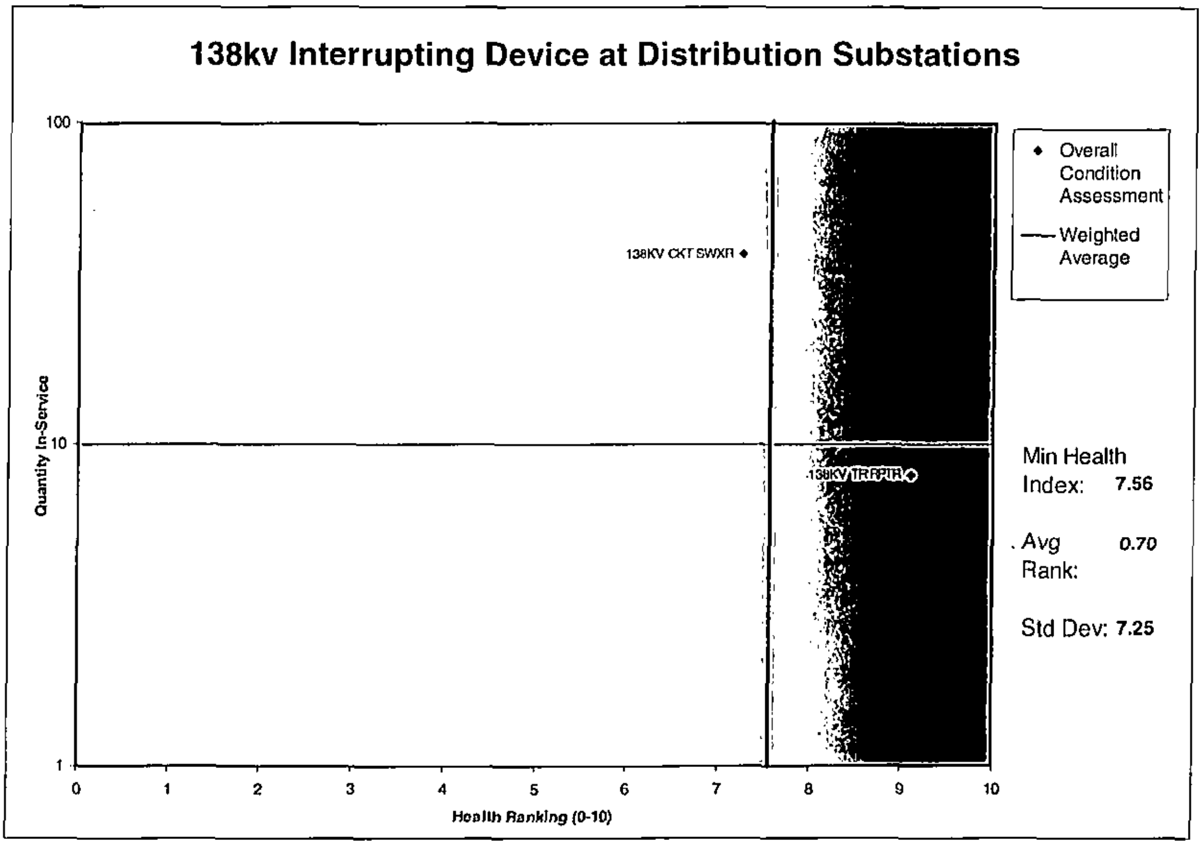
6.2 Substation



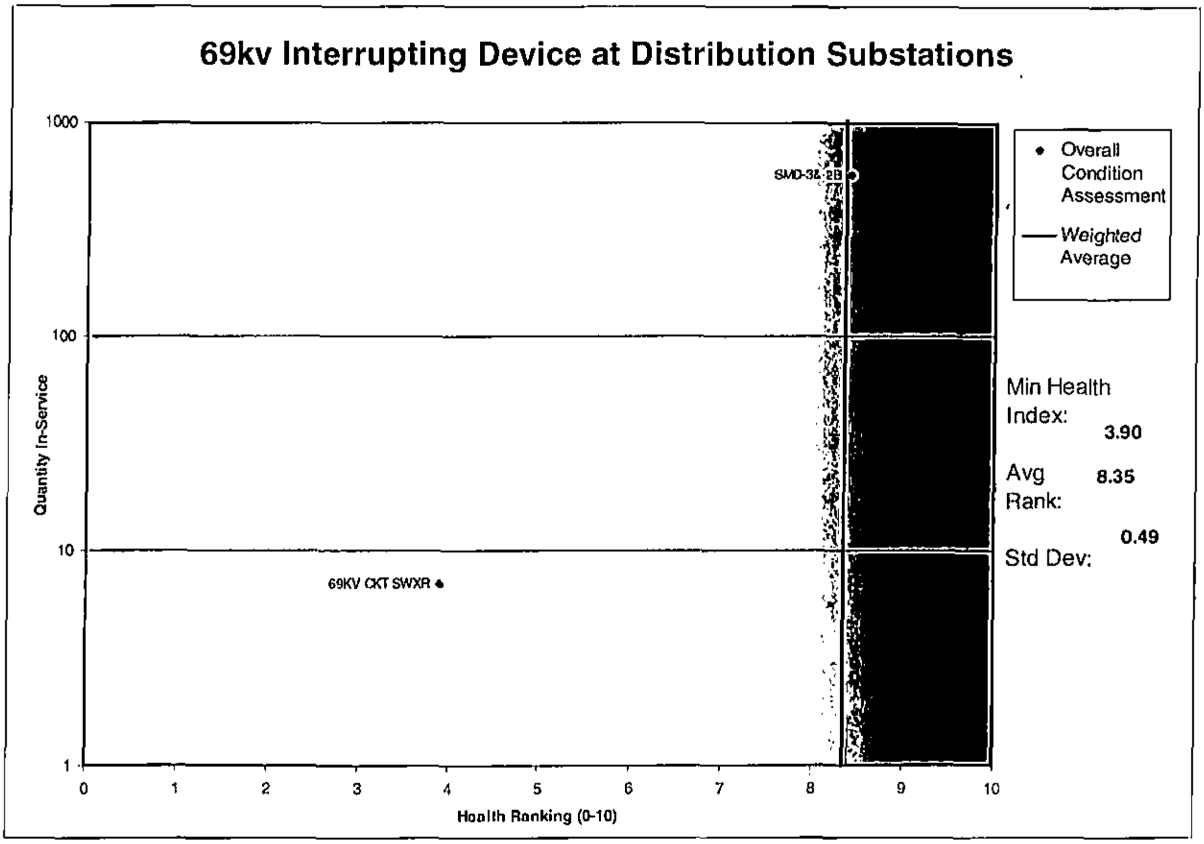
The following 12kv circuit breakers are rated “Poor” or “Marginal” largely based on age, chronic operating issues and lack of spare/repair parts and vendor technical support:

- GE type FHKO, FK and FKD OCBs
- Allis Chalmers type OZ and FZO OCBs
- Federal Pacific type AF and JCE OCBs
- Westinghouse type G, GO and GC OCBs
- Roller Smith type OC OCBs
- Allis Chalmers type MC ACBs
- McGraw Edison type WSA OCBs
- GE type AM ACBs
- GE type VIB VCBs
- McGraw Edison type VAC VCBs

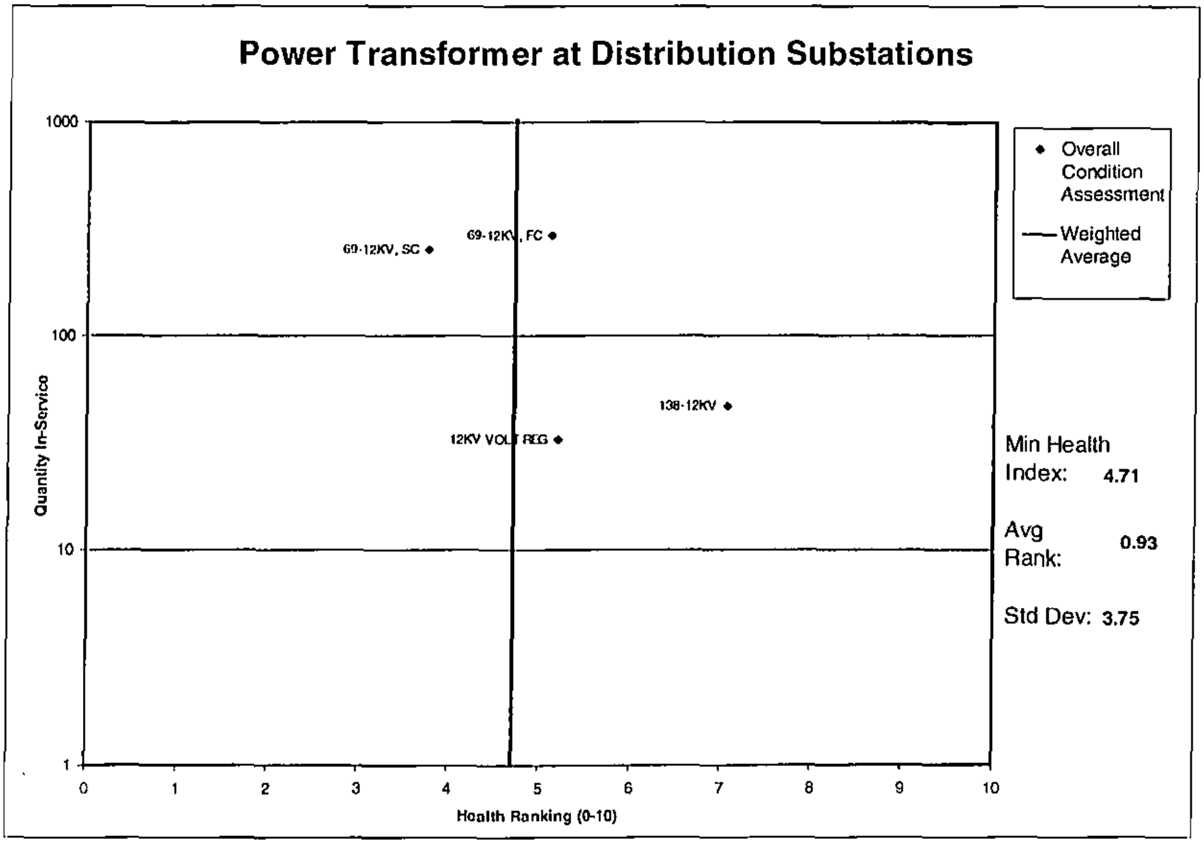
These breakers have tailored but similar plans that address systematic replacement over the next 10 years plus an improved maintenance optimization strategy aimed to improve service reliability.



All devices in this asset class are relatively young and to date have been performing satisfactory; no requirement for capital replacements at this time.

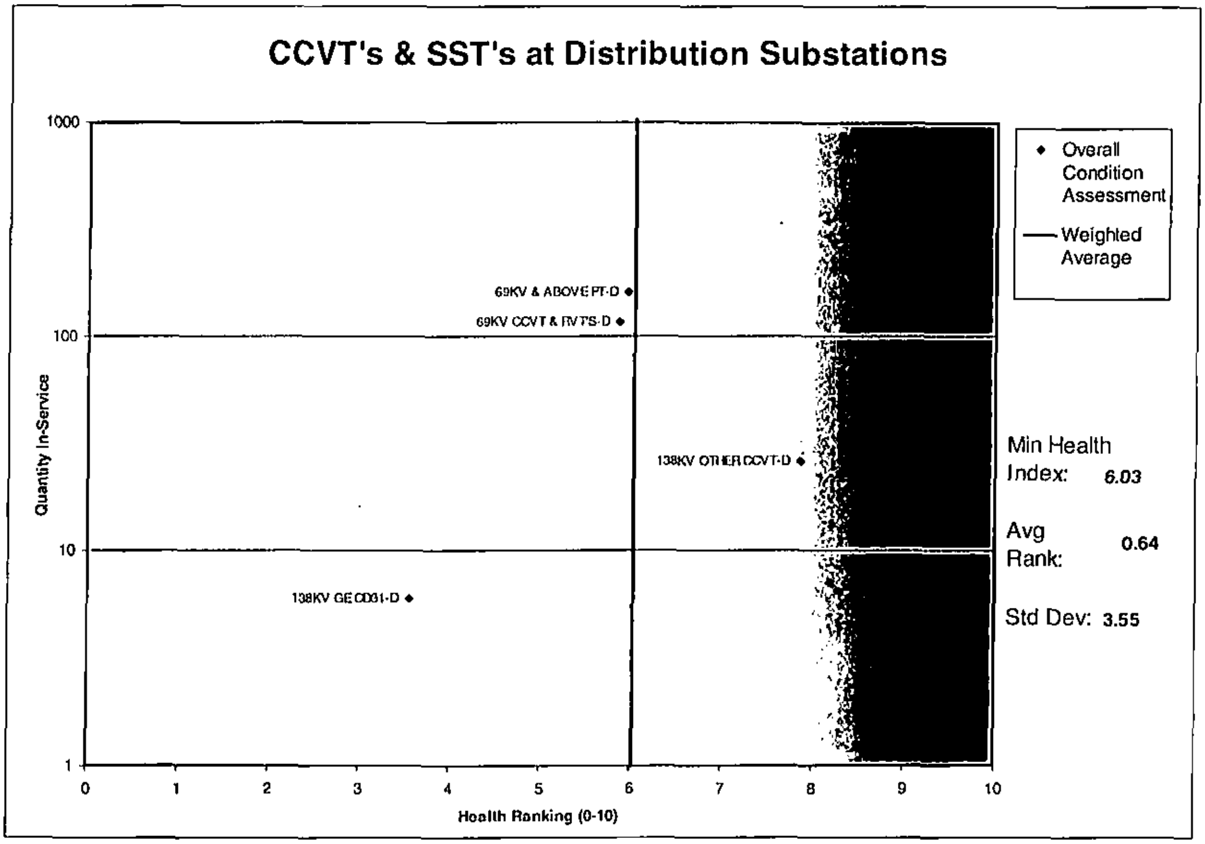


This asset group is largely comprised of 69kv single-pole power fuses which are rated "Excellent". However, there are 7 vintage design 69kv circuit switchers that are just inside the "Marginal" rating due lack of continued vendor support for the style of circuit switcher. There is no funding planned for the next 10 year timeframe; device would be replaced with a current design if failure would occur. However, budget consideration should be made for ultimate replacement sometime in the 2021 – 2025 timeframe.

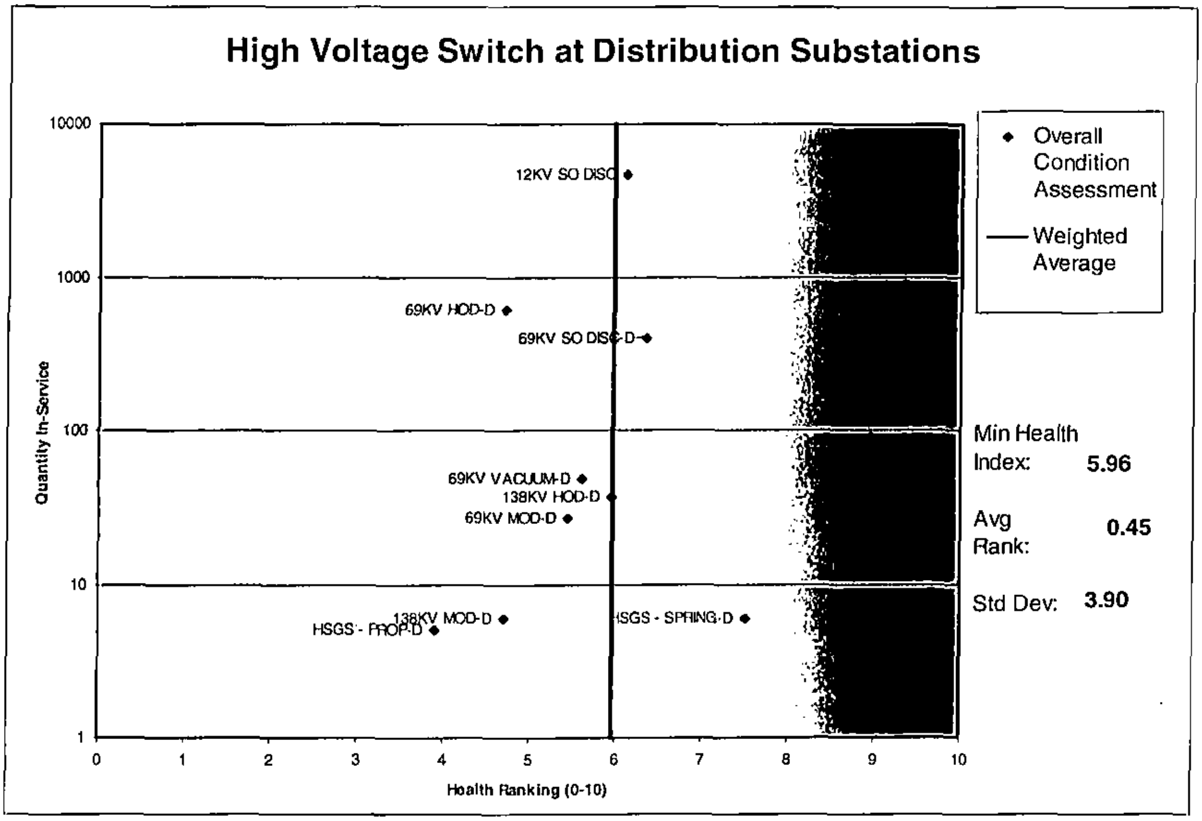


69-12kv self-cooled power transformers are rated "Marginal" based on the age of the total population. All other devices in this asset class are rated "Good" or better.

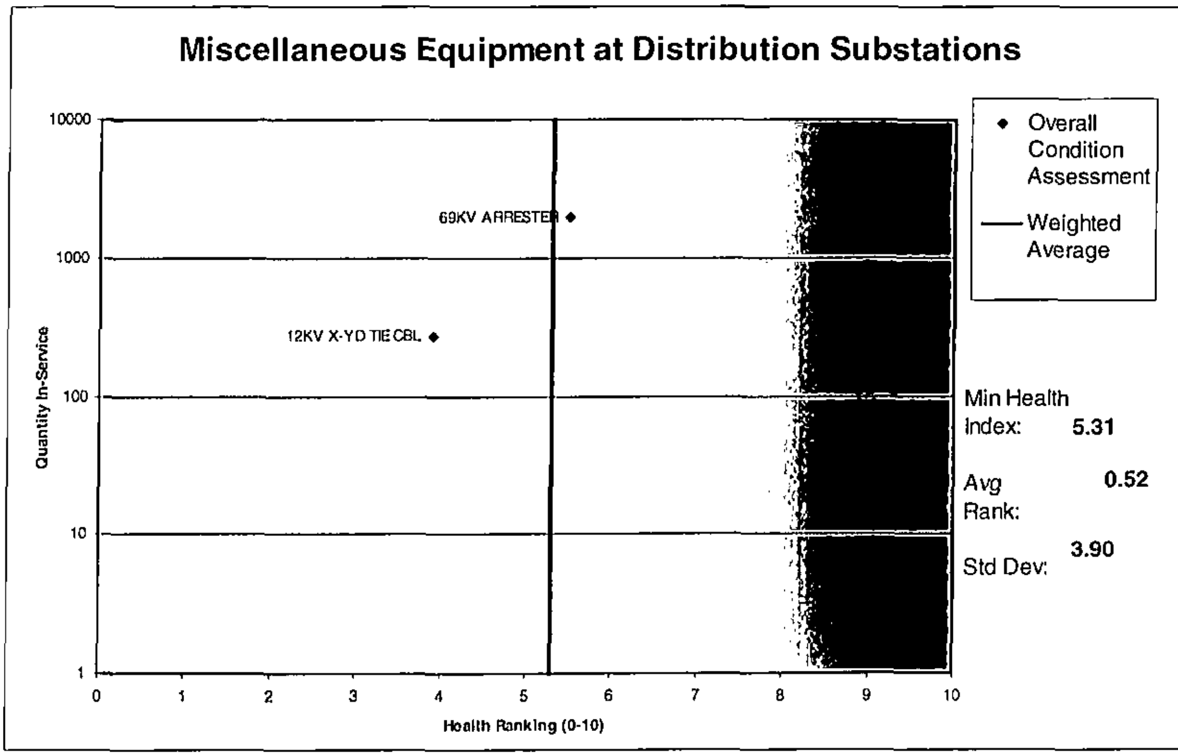
The proposed capital replacement program recommends, to stay within expected life cycle, replacement of about 4 self-cooled transformers per year over the 2010 – 2020 timeframe and stepped up to approximately 8 per year thereafter to stem the approaching wave.



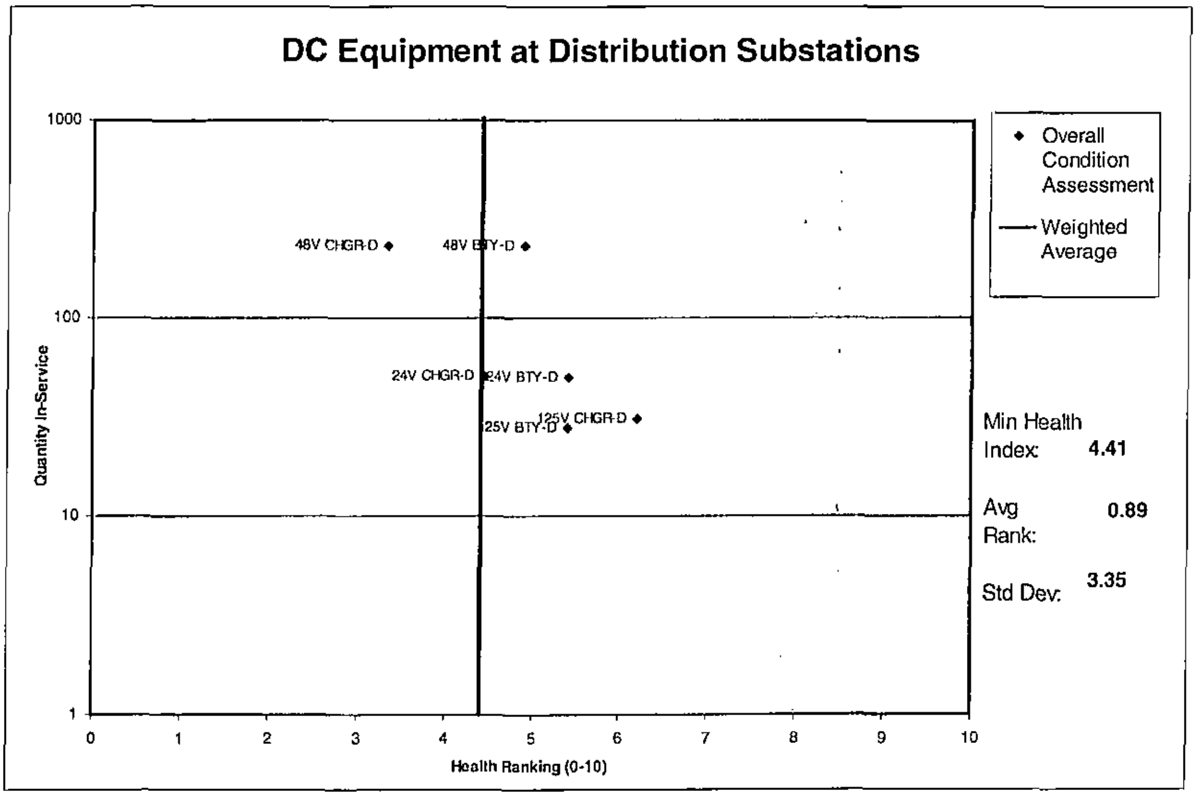
This asset class is largely rated as "Good" or better except for the eight 138kv GE type CD-31 CCVTs at Allentown Substation which are rated "Marginal". These devices have an industry and PPL history of violent I/S failure. These devices are part of an overall 10-year capital replacement program to eliminate from the PPL system. However, an opportunity existed to include them in the scope of a 2008 breaker replacement project; all devices will be replaced by early 2009.



The high voltage switch asset class is largely rated "Good" or better. However, there are a handful of propellant-actuated high speed ground switches, the technology for which is no longer supported by the vendor. This device requires a proprietary 'charge' to initiate blade movement which is no longer available and cannot be reverse-engineered. As such, limited quantity on-hand must be reserved for replenishment when the device operates; there are not enough for long-term operational and testing needs. The capital replacement plan recommends replacement of these devices 1 per year beginning in 2010.



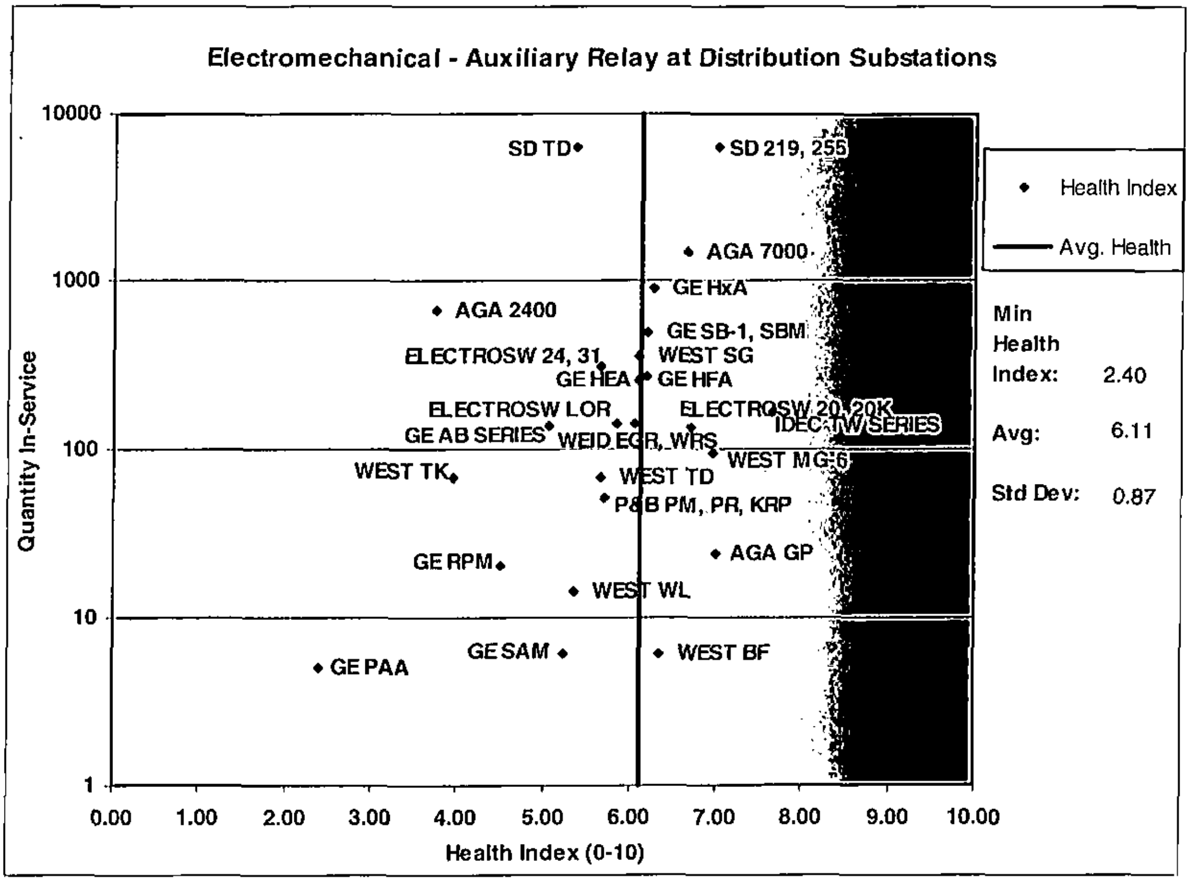
In the miscellaneous equipment asset class, the 272 three-phase 12kv underground cable circuits are rated “Marginal” due to high average age of the group and Doble test results. The capital replacement plan recommends 12 circuits per year be replaced through the 2010 – 2020 timeframe. It also includes suggestions for redesign of the connection to eliminate the cable completely where possible (i.e.: design an open-air insulated connection between existing connection points).



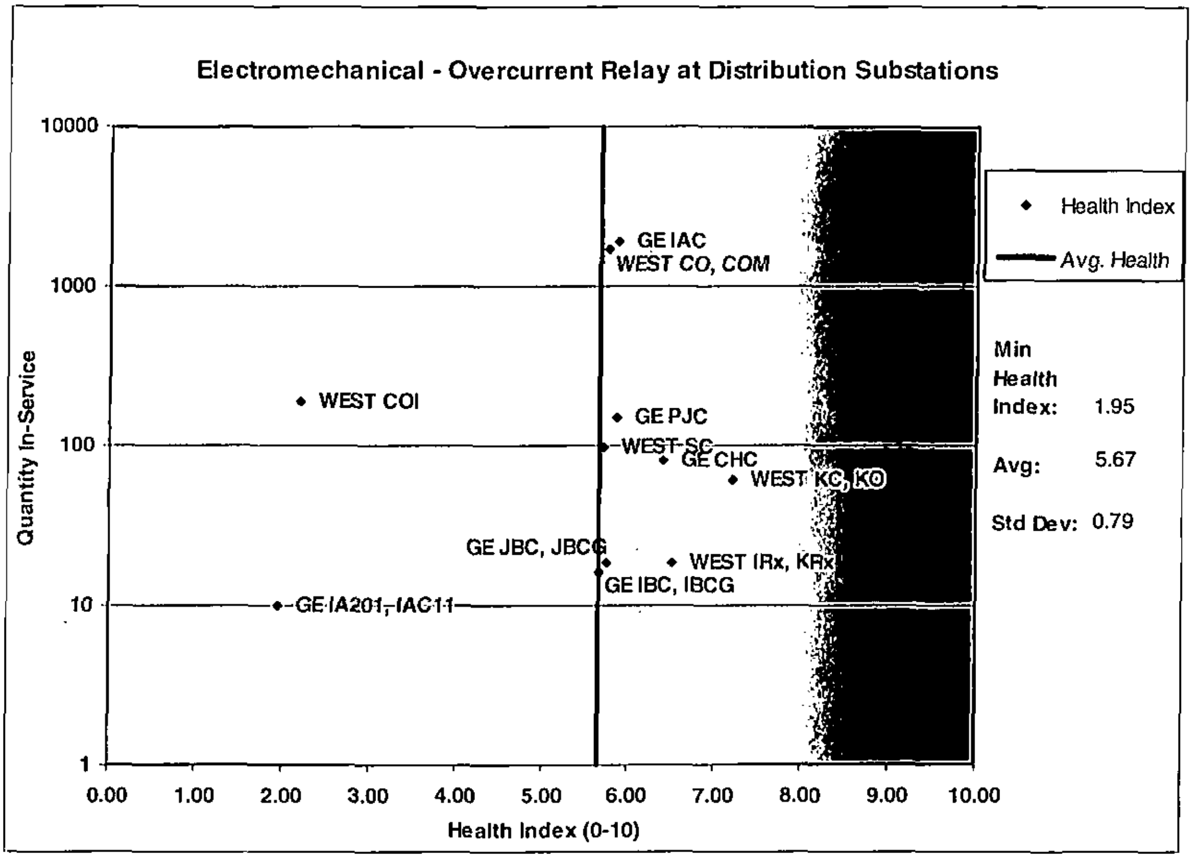
With the exception of the 234 48-volt battery chargers which are rated "Marginal" all other devices in the DC equipment asset class are rated "Good" or better.

The 48-volt chargers have a relatively high average age and pose ongoing operational problems. Often, adequate spare parts do not exist, can't be obtained from industry, or are too expensive relative to the cost of a replacement unit. As such, the capital replacement program recommends an annual replacement of 20 chargers per year from 2010 thru 2013 inclusive to aggressively address those units already beyond design life and the oncoming 'wave' that will reach design end-of-life in the next 10 years. Beyond 2013, the annual rate is lowered to 4 chargers per year.

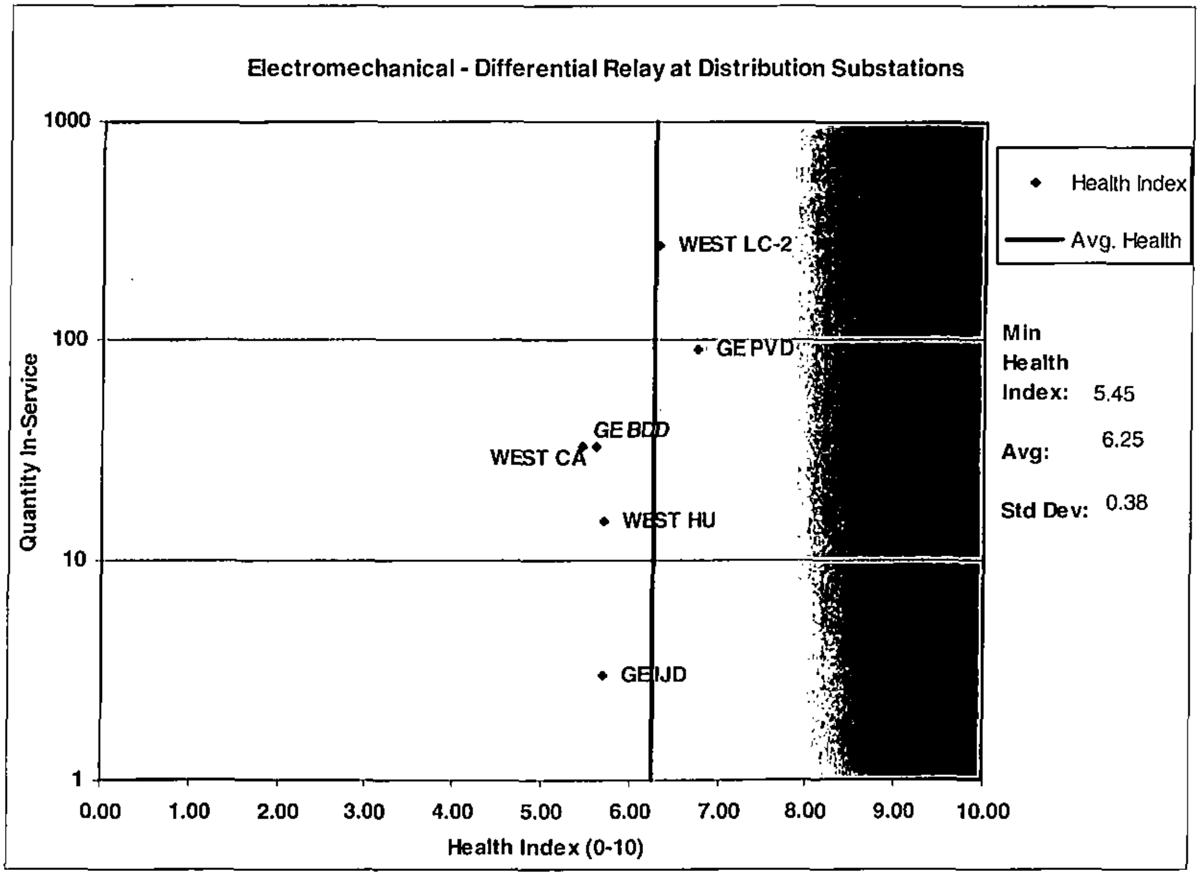
6.3 Protection and Control Section



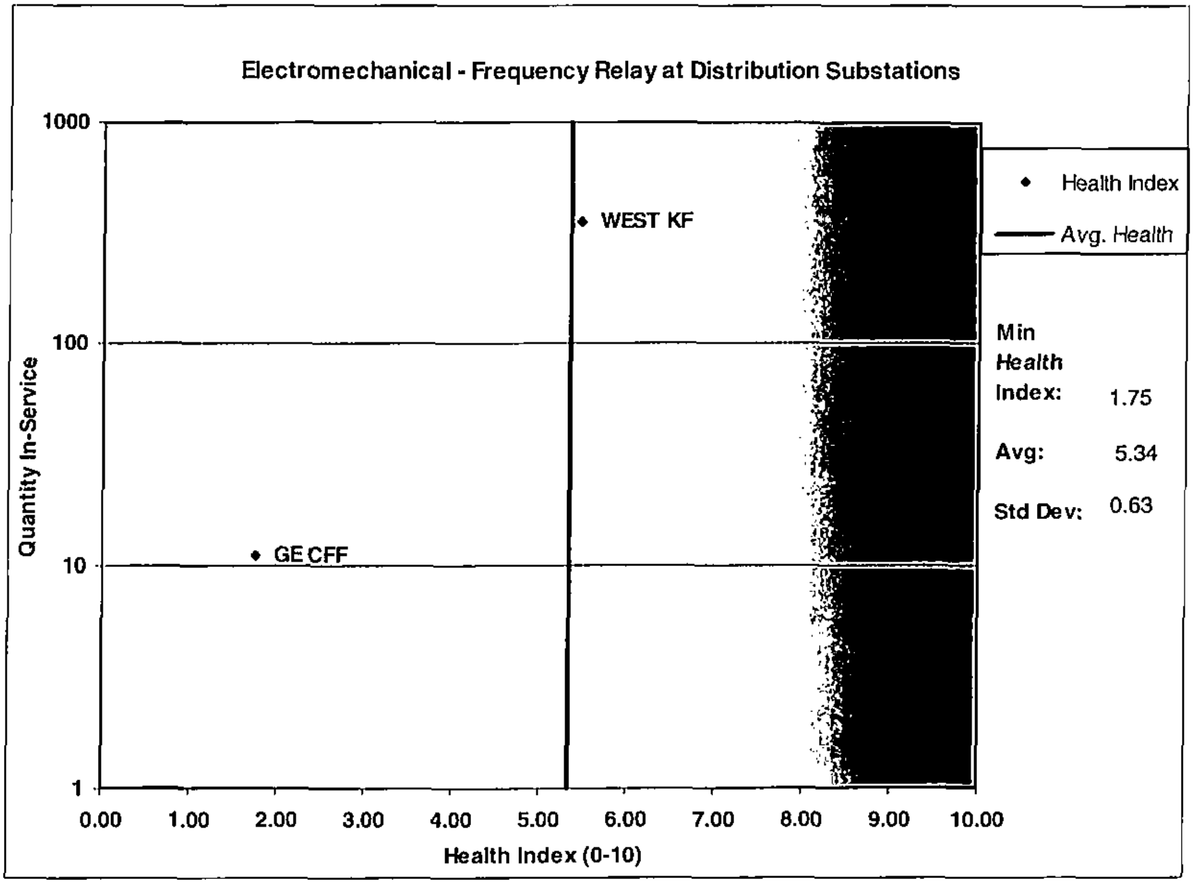
Most electromechanical auxiliary relays are of good health. However, the Agastat 2400, General Electric type PAA, and Westinghouse type TK are obsolete timing auxiliary relays used mostly in 12kV circuit breakers. They are in marginal condition based on age, relay obsolescence, lack of spare parts, and no vendor support. The failure rate of these relays is low, and thus they don't have a poor condition rating. However, they should be replaced with new Agastat pneumatic relays.



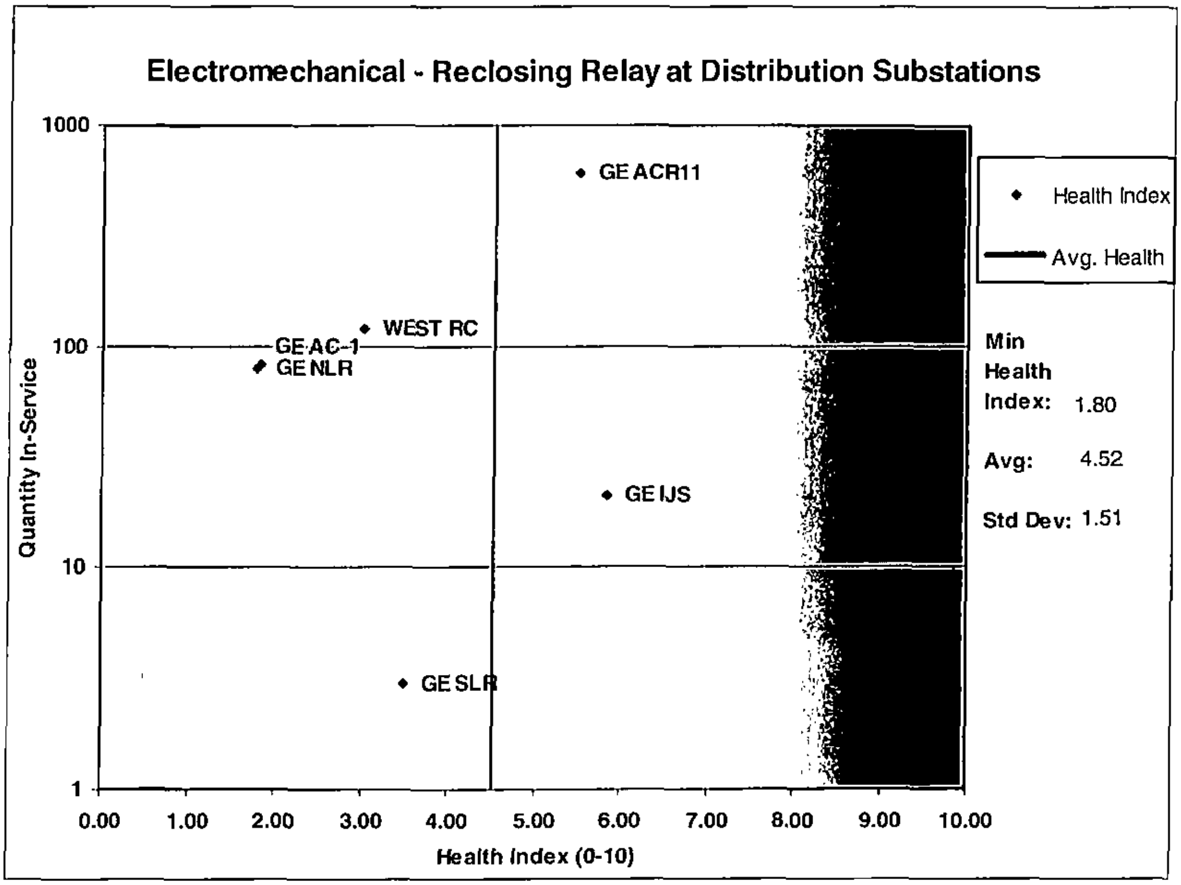
Most electromechanical overcurrent relays are in good and very good condition. These relays have a very low failure rate, durable, and have a long life expectancy. It is expected that relays in this asset class have a life expectancy of greater than 60 years. However, the Westinghouse COI and General Electric type IA201 & IAC11 relays are in marginal and poor condition based on relay performance, obsolescence, lack of technical knowledge, and no vendor support. These relays are close to the life expectancy of 60 years.



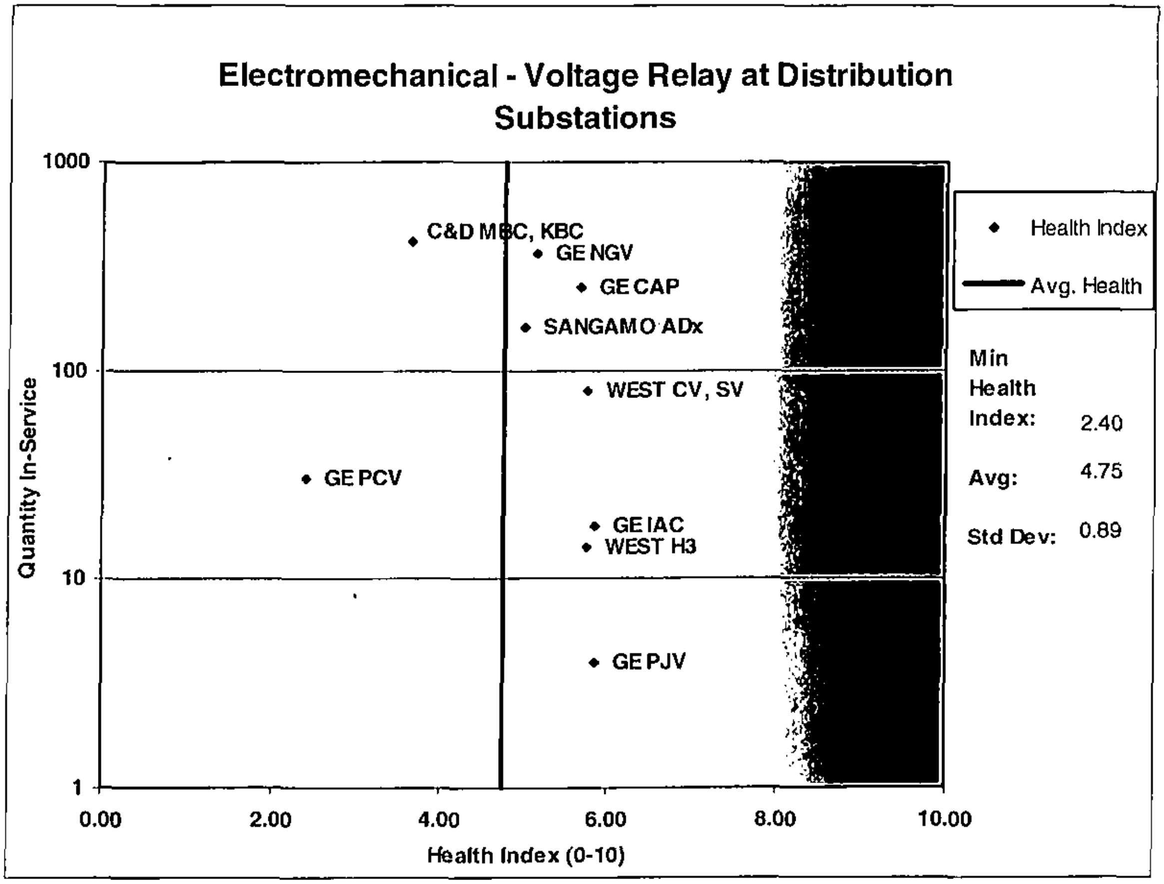
All electromechanical differential relays are in good or very good condition. Most are still being supported by equipment manufacturers. Additionally, we have ample technical experience, spare parts, and knowledge to support these relays. There is no recommendation to replace these relays as part of a capital replacement program at this time.



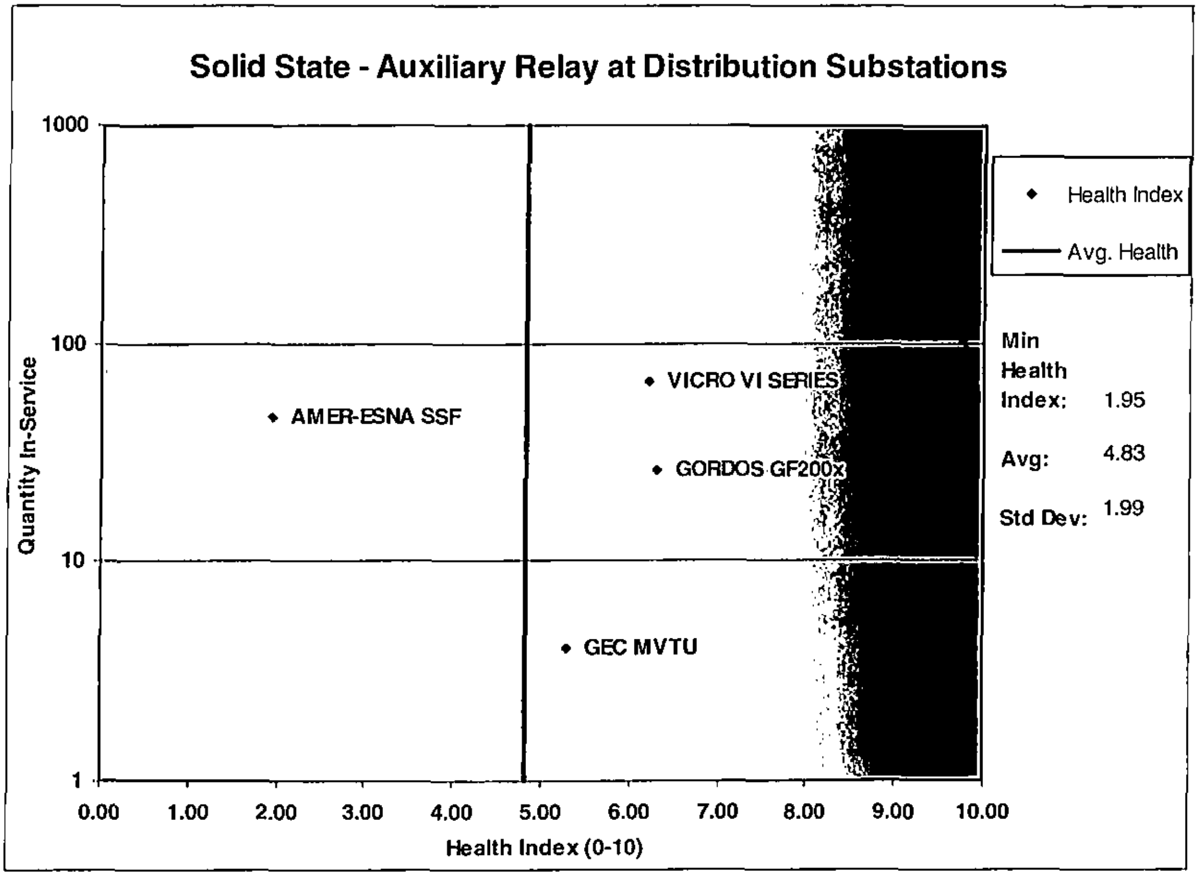
In general, the Westinghouse KF underfrequency relays are in good condition. They are reliable relays with a very low failure rate. In addition, they are easy to isolate, repair, and maintain. The General Electric type CFF underfrequency relays are in poor condition. The stability of the protective frequency setting is an issue. Due to leaky and drifting capacitors, the frequency setting on this relay would drift causing *unintended relay operation. This would result in the loss of customers at substations* where underfrequency load shed schemes are installed. In addition, with regard to the CFF relays, we have limited spare parts and vendor support.



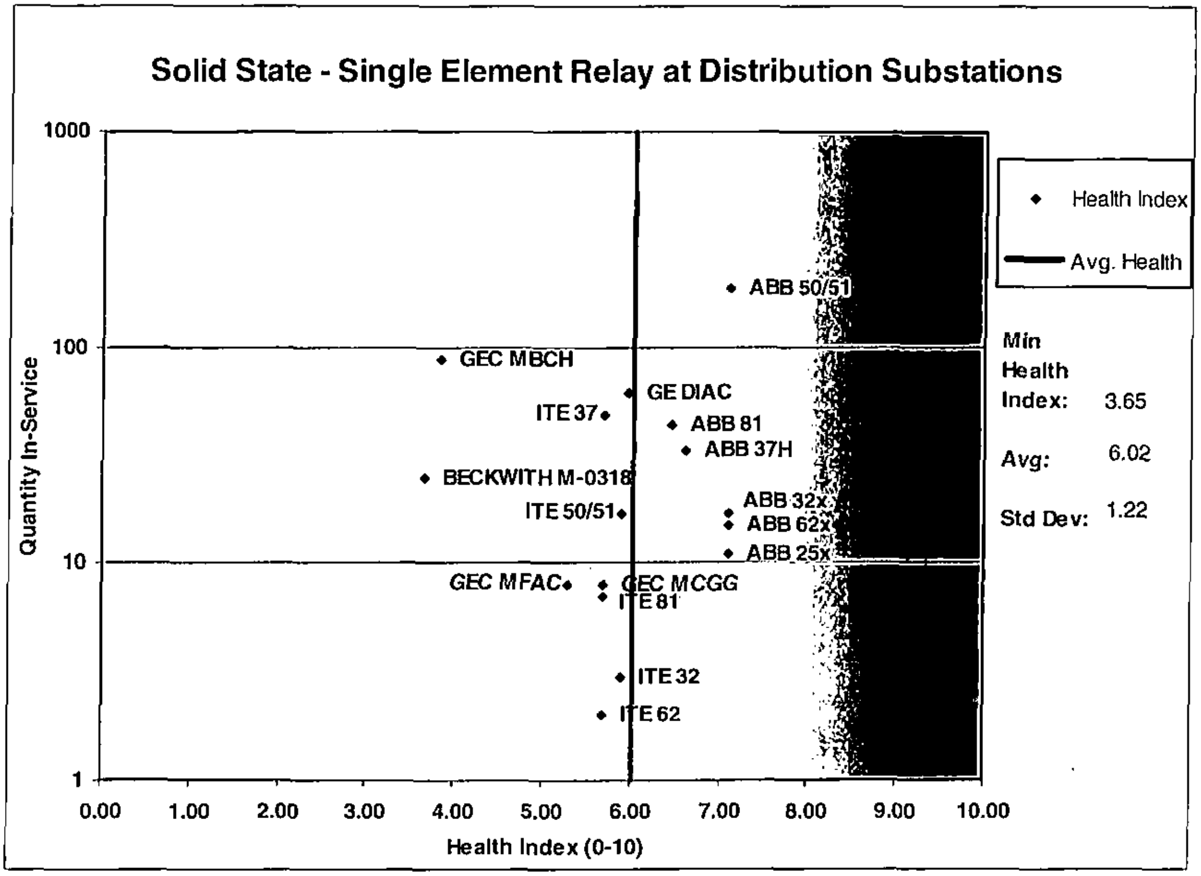
In general, electromechanical reclosing relays are complex devices. They are difficult to repair and maintain due to the vast number of components contained within the relay. The General Electric type AC-1, General Electric type LR, and Westinghouse type RC reclosing relays are in poor and marginal condition based on relay obsolescence, lack of spare parts and vendor support. Additionally, these relays cannot be repaired due to the mechanical design. General Electric ACR reclosing relays are in good condition. Adequate spare parts are available to repair and replace these relays in the event of relay failure.



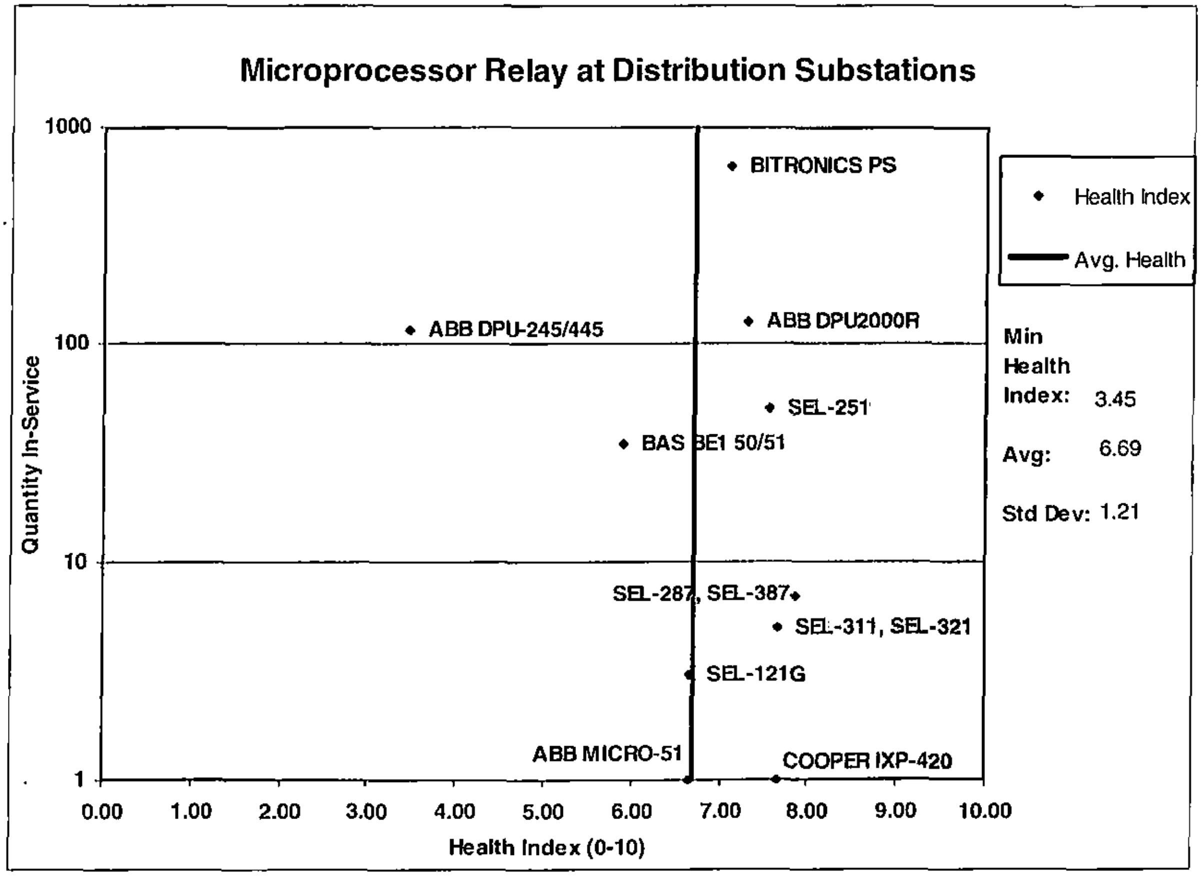
The majority of the electromechanical voltage relays are in good and very good condition. These relays have a very low failure rate, durable, and have a long life expectancy. It is expected that relays in this asset class have a life expectancy of greater than 60 years. The C&D voltage relays are battery monitoring devices that are poor performers and should be replaced as part of a capital replacement program. In addition, the General Electric type PCV voltage relays are in poor condition and should be replaced.



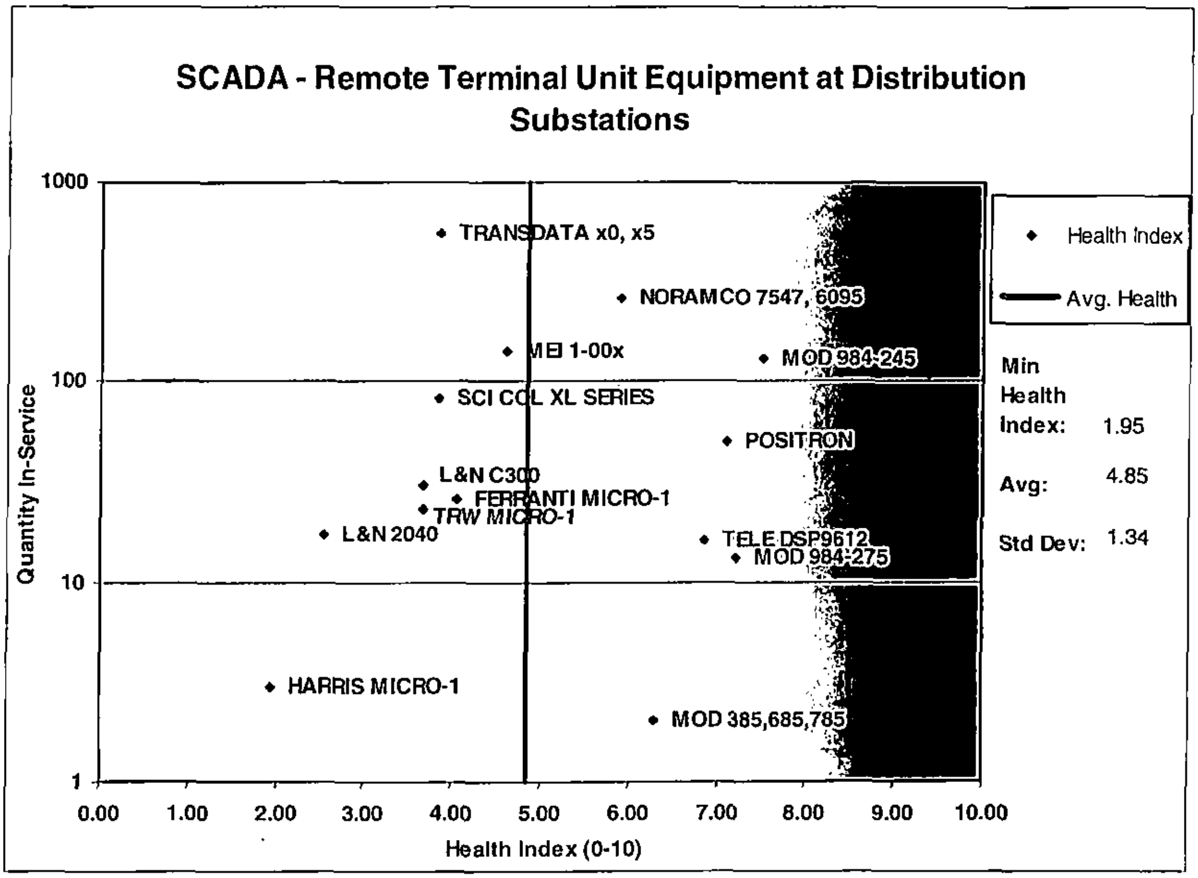
The majority of the solid-state auxiliary relays are in good and very good condition. These relays have a very low failure rate, durable, and have a long life expectancy. The Amerace SSF solid-state timers are marginal performers and should be replaced as part of a capital replacement program. The Amerace SSF timers are susceptible to triggering on system transients and should be replaced with Agastat pneumatic timers when possible.



The majority of the solid-state relays are in good and very good condition. However, the GEC MBCH and the Beckwith M-0318 relays are in marginal condition based on relay obsolescence, lack of spare parts and vendor support. These relays should be replaced with modern microprocessor-based relays due to significant technical issues effecting the performance and reliability of the relay. In addition, the Beckwith M-0318 does not account for daylight savings time and thus requiring annual maintenance to support this relay.



The average health of microprocessor-based distribution relays is very good. However, the ABB DPU-245/445 relays are marginal. There are significant technical issues with this relay and the recent failures went undetected resulting in loss of phase protection. These relays have no conformal coating on the circuit boards. Relay failures are expected to increase as equipment ages. These relays should be *replaced with ABB DPU2000R relays due to reliability concerns, replacement issues,* and very limited spare parts. In addition modern microprocessor relays are easier to maintain and test.



The health assessment of SCADA Remote Terminal Units (RTU) ranges from poor to very good. There is a capital replacement program to replace legacy SCADA RTUs over the next 10 years. All Micro 1 protocol and L&N C300 SCADA RTUs are in marginal condition, except for the original Harris RTU. The Harris RTU is in poor condition primarily due to age. These RTUs should be replaced with microprocessor-based SCADA RTUs due to obsolescence, lack of spare parts and no vendor support. In addition, all transducers shall be replaced with multifunction digital meters.

7 Detailed Supporting Data

7.1 Information Collected to support this program

The information developed to support the preparation of this report resides in an extensive database. Detailed reports generated in the database can be printed and made available to supplement this portion of the report. Each set of 2-3 pages from those printouts is devoted to an individual device group and contains all of the information described in the list below.

For Each Asset Class
Each Equipment Class
Each Device

- General Identification data
- Age Summary (Min., Max., Mean, PPL Expected life, etc.)
- Condition Assessment Health Index development (Criteria, weightings, and ratings)
- Failure Mode/ Impact of a failure / Recovery plan for responding to a failure (1, 2, or 3 of these)
- Present Maintenance Plan description of activities
- Optimized Maintenance Plan description of activities
- Capital Replacement Plan budget
- Recovery Plan for failure response
- Reliability Criteria analysis (Projected change to annual # of failures over the 10 year period)
- SAIFI/SAIDI change calculation (Projected change to SAIFI over the 10 year period)
- Financial Estimates of projected Capital and Expense expenditures for 2010 – 2020 required to implement the recommended actions.

As of January 2009, the database included approximately 675 device records.

7.2 Equipment not included in the evaluation.

PPLE T&D system equipment Identified by Maintenance Optimization Strategy that, but was not included in the evaluation.

Grounding -- Transmission, distribution, and substation
Substation control and protection system cables
Equipment control cabinet components
Customer meters
AMR equipment
Buildings (maintenance items HVAC, roof)
Fences
Spare parts and stocked materials
Other communications devices (partial)
Lighting (except Street lights)
Cathodic Protection systems

Other assets owned by PPLE but not part of the T& D system to deliver energy to our customers is not included

Real Estate, land, buildings, offices, warehouses, Service Centers, etc.
Office fixtures, furniture, supplies etc.
Vehicle and heavy equipment fleets
Vegetation – Tree Trimming, Weed spraying, Snowplowing, etc.
Soil Erosion and all other real estate, or right of way issues.

Appendix A Financial Details

Note: All of the cost estimates presented in this report are in current year dollars, *and were not escalated in the cost projections.*

Capital Plan Costs and projections 2010—2020 Dollars (in thousands)

	Protection & Control											
MICROPROCESSOR	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	Total
Present Capital	450	450	450	450	450	0	0	0	0	0	0	2,250
Recommended Capital	450	450	450	450	450	225	225	225	225	100	100	3,350
Change to Capital	0	0	0	0	0	225	225	225	225	100	100	1,100
SOLID STATE	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	Total
Present Capital	0	0	0	0	0	0	0	0	0	0	0	0
Recommended Capital	15	15	15	15	15	15	15	15	15	15	15	165
Change to Capital	15	15	15	15	15	15	15	15	15	15	15	165
ELECTROMECHANICAL	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	Total
Present Capital	8	8	8	8	8	8	8	8	8	8	8	88
Recommended Capital	1,688	1,693	1,648	1,653	1,550	1,433	1,433	1,393	1,393	1,393	1,393	16,670
Change to Capital	1,680	1,685	1,640	1,645	1,542	1,425	1,425	1,385	1,385	1,385	1,385	16,582
SCADA - REMOTE TERMINAL UNI	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	Total
Present Capital	1,340	2,451	1,987	2,050	74	253	0	0	0	0	0	8,155
Recommended Capital	1,540	2,651	2,187	2,450	1,074	1,253	2,000	2,000	2,000	2,000	1,800	20,955
Change to Capital	200	200	200	400	1,000	1,000	2,000	2,000	2,000	2,000	1,800	12,800
	Distribution sub team											
POLES AND STRUCTURES	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	Total
Present Capital	10,000	10,700	11,000	11,100	11,300	11,500	11,700	11,900	12,100	12,300	12,500	126,100
Recommended Capital	11,700	12,400	12,700	12,800	13,000	13,200	13,400	13,600	13,800	14,000	14,200	144,800
Change to Capital	1,700	1,700	1,700	1,700	1,700	1,700	1,700	1,700	1,700	1,700	1,700	18,700
TRANSFORMERS	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	Total
Present Capital	462	805	510	650	700	700	700	700	700	700	700	7,327
Recommended Capital	462	805	510	650	700	1,250	1,250	1,250	1,250	1,250	1,250	10,627
Change to Capital	0	0	0	0	0	550	550	550	550	550	550	3,300
SECTIONALIZING	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	Total
Present Capital	1,299	1,299	1,299	1,299	1,299	1,299	1,299	1,299	1,299	1,299	1,299	14,289
Recommended Capital	1,503	1,503	1,503	1,503	1,503	1,503	1,503	1,503	1,503	1,503	1,503	16,533
Change to Capital	204	204	204	204	204	204	204	204	204	204	204	2,244
CONDUCTOR AND CABLE	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	Total
Present Capital	8,000	8,000	8,000	8,000	8,000	8,000	8,000	8,000	8,000	8,000	8,000	88,000
Recommended Capital	54,520	54,520	54,450	54,450	54,450	51,750	51,750	51,750	51,750	51,750	51,750	582,890
Change to Capital	46,520	46,520	46,450	46,450	46,450	43,750	43,750	43,750	43,750	43,750	43,750	494,890
POLE LINE HARDWARE	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	Total
Present Capital	0	0	0	0	0	0	0	0	0	0	0	0
Recommended Capital	0	0	0	0	0	0	0	0	0	0	0	0
Change to Capital	0	0	0	0	0	0	0	0	0	0	0	0
VOLTAGE CONTROL	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	Total
Present Capital	0	0	0	0	0	0	0	0	0	0	0	0
Recommended Capital	0	0	0	0	0	0	0	0	0	0	0	0
Change to Capital	0	0	0	0	0	0	0	0	0	0	0	0

Capital Plan Costs and projections 2010—2020 Dollars (in thousands)
(continued)

	Substation sub team											
TRANSFORMER	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	Total
Present Capital	0	0	0	0	0	0	0	0	0	0	0	0
Recommended Capital	7,020	6,975	6,975	6,975	7,000	6,860	6,860	6,860	7,685	7,685	7,685	78,580
Change to Capital	7,020	6,975	6,975	6,975	7,000	6,860	6,860	6,860	7,685	7,685	7,685	78,580
138KV INTERRUPTING DEVICE	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	Total
Present Capital	0	0	0	0	0	0	0	0	0	0	0	0
Recommended Capital	0	0	0	0	0	0	0	0	0	0	0	0
Change to Capital	0	0	0	0	0	0	0	0	0	0	0	0
69KV INTERRUPTING DEVICE	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	Total
Present Capital	0	0	0	0	0	0	0	0	0	0	0	0
Recommended Capital	60	60	60	60	60	60	60	60	60	60	60	660
Change to Capital	60	60	60	60	60	60	60	60	60	60	60	660
12KV INTERRUPTING DEVICE	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	Total
Present Capital	0	0	0	0	0	0	0	0	0	0	0	0
Recommended Capital	4,680	4,085	4,255	5,700	5,700	5,870	5,700	5,615	5,700	6,380	5,700	59,385
Change to Capital	4,680	4,085	4,255	5,700	5,700	5,870	5,700	5,615	5,700	6,380	5,700	59,385
SWITCH, HV	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	Total
Present Capital	0	0	0	0	0	0	0	0	0	0	0	0
Recommended Capital	1,058	1,058	842	842	842	1,440	1,440	1,440	1,440	1,508	1,508	13,418
Change to Capital	1,058	1,058	842	842	842	1,440	1,440	1,440	1,440	1,508	1,508	13,418
DC EQUIPMENT	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	Total
Present Capital	0	0	0	0	0	0	0	0	0	0	0	0
Recommended Capital	415	425	425	425	265	215	175	160	145	130	115	2,895
Change to Capital	415	425	425	425	265	215	175	160	145	130	115	2,895
MISCELLANEOUS DEVICE	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	Total
Present Capital	0	0	0	0	0	0	0	0	0	0	0	0
Recommended Capital	1,392	1,392	1,392	1,392	1,392	1,392	1,392	1,392	1,392	1,392	1,392	15,312
Change to Capital	1,392	1,392	1,392	1,392	1,392	1,392	1,392	1,392	1,392	1,392	1,392	15,312
Total	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	Total
Present Capital	21,559	23,713	23,254	23,557	21,831	21,760	21,707	21,907	22,107	22,307	22,507	246,209
Recommended Capital	86,503	88,032	87,412	89,365	88,001	86,466	87,203	87,263	88,358	89,166	88,471	966,240
Change to Capital	64,944	64,319	64,158	65,808	66,170	64,706	65,496	65,356	66,251	66,859	65,964	720,031
Distribution Capital Totals	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	Total
Present Capital	21.6	23.7	23.3	23.6	21.8	21.8	21.7	21.9	22.1	22.3	22.5	246.2
Recommended Capital	86.5	88.0	87.4	89.4	88.0	86.5	87.2	87.3	88.4	89.2	88.5	966.2
Change to Capital	64.9	64.3	64.2	65.8	66.2	64.7	65.5	65.4	66.3	66.9	66.0	720.0

All of the cost estimates presented in this report are in current year dollars, and were not escalated in the cost projections.

Additional Capital Replacement Projects not included in the summary above.

The Distribution line sub-team has proposed capital replacements of several line sections. These are not included in Capital costs above, which are focused on the replacement of structures and components as a part of the routine maintenance and care of the distribution system. These costs are in addition to the capital expenditures estimated in the table above.

The projected annual costs of the line replacement program that has been proposed are captured below.

Distribution Capital	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	Total $M
Capital Line Replacement	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	15.4

Note: All of the cost estimates presented in this report are in current year dollars (2008) dollars, and were not escalated in the cost projections.

This projection is based on the plan described in the Capital Replacement Methodology section 4.1.1.

Distribution Circuits Replacement Program

- In addition, a capital equipment replacement program should be established to identify a select group of distribution circuits that have exhibited unusually high equipment failure rates during the past several years. Equipment will be replaced on a per circuit basis where the greatest risk of failure exists, based upon available historical reliability information, as well as health assessment data.
- The recommendation is that all resulting circuits should be addressed in the next 10 years. That results in 100 circuits per year.

The estimated cost to replace this equipment on a per circuit basis is $140,000, or $6,000 per circuit mile.

To help mitigate the risk of incurring additional equipment failures and resultant power interruptions, the team has recommended that $1,400,000 in capital be included in the annual budget to fund this program. The methodology used to select and prioritize the circuits should focus on both historical reliability performance and the relative health of the circuits and associated equipment.

Maintenance Plan Costs and projections 2010—2020 Dollars (in thousands)

	Protection & Control											
MICROPROCESSOR	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	Total
Present Expense	106	106	106	106	106	106	106	106	106	106	106	1,166
Recommended Expense	135	128	123	118	113	108	103	98	93	88	83	1,190
Change to Expense	29	22	17	12	7	2	-3	-8	-13	-18	-23	24
SOLID STATE	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	Total
Present Expense	76	76	76	76	76	76	76	76	76	76	76	836
Recommended Expense	82	82	81	81	80	80	76	79	78	75	78	872
Change to Expense	6	6	5	5	4	4	0	3	2	-1	2	36
ELECTROMECHANICAL	*2010*	*2011*	*2012*	*2013*	*2014*	*2015*	*2016*	*2017*	*2018*	*2019*	*2020*	*Total*
Present Expense	1,022	1,022	1,019	1,019	1,019	1,019	1,019	1,019	1,019	1,019	1,019	11;215
Recommended Expense	1,093	1,059	1,018	970	1,062	911	877	832	800	770	752	10,144
Change to Expense	71	37	-1	-49	43	-108	-142	-187	-219	-249	-267	-1,071
SCADA - REMOTE TERMINAL UNI	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	Total
Present Expense	167	147	141	135	127	123	121	118	115	112	110	1,416
Recommended Expense	167	147	140	131	118	109	104	96	90	81	76	1,259
Change to Expense	0	0	-1	-4	-9	-14	-17	-22	-25	-31	-34	-157
	Distribution sub team											
POLES AND STRUCTURES	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	Total
Present Expense	*3,800*	*4,100*	*4,200*	*4,325*	*4,400*	*4,500*	*4,600*	*4,700*	*4,800*	*4,900*	*5,000*	49,325
Recommended Expense	4,934	5,234	5,334	5,459	5,534	5,634	5,734	5,834	5,934	6,034	6,134	61,799
Change to Expense	1,134	1,134	1,134	1,134	1,134	1,134	1,134	1,134	1,134	1,134	1,134	12,474
TRANSFORMERS	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	Total
Present Expense	3,105	3,105	3,105	3,105	3,205	3,205	3,205	3,305	3,405	3,505	3,505	35,755
Recommended Expense	3,585	3,585	3,685	3,685	3,705	3,765	3,695	3,745	3,745	3,745	3,735	40,675
Change to Expense	480	480	580	580	500	560	490	440	340	240	230	4,920
SECTIONALIZING	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	Total
Present Expense	606	606	609	609	614	614	619	619	624	624	624	6,768
Recommended Expense	*1,056*	*1,056*	*1,076*	*1,076*	*1,111*	*1,111*	*1,146*	*1,146*	*1,181*	*1,181*	*1,181*	*12,325*
Change to Expense	452	452	467	467	497	497	527	527	557	557	557	5,557
CONDUCTOR AND CABLE	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	Total
Present Expense	2,010	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	22,010
Recommended Expense	8,333	8,321	8,315	8,315	8,315	8,150	8,150	8,150	8,150	8,150	8,150	90,499
Change to Expense	6,323	6,321	6,315	6,315	6,315	6,150	6,150	6,150	6,150	6,150	6,150	68,489
POLE LINE HARDWARE	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	Total
Present Expense	760	264	271	271	278	278	285	285	292	292	297	3,573
Recommended Expense	1,337	289	296	296	303	303	310	310	317	317	322	4,400
Change to Expense	577	25	25	25	25	25	25	25	25	25	25	827
VOLTAGE CONTROL	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	Total
Present Expense	272	760	760	760	760	760	760	760	760	760	760	7,872
Recommended Expense	297	1,337	1,337	1,337	1,337	1,337	1,337	1,337	1,337	1,337	1,337	13,667
Change to Expense	25	577	577	577	577	577	577	577	577	577	577	5,795

Maintenance Plan Costs and projections 2010—2020 Dollars (in thousands)
(continued)

	Substation sub team											
TRANSFORMER	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	Total
Present Expense	427	427	427	427	427	427	427	427	427	427	427	4,697
Recommended Expense	598	598	598	598	598	598	598	598	598	598	598	6,578
Change to Expense	171	171	171	171	171	171	171	171	171	171	171	1,881
138KV INTERRUPTING DEVICE	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	Total
Present Expense	21	21	21	21	21	21	21	21	21	21	21	231
Recommended Expense	21	21	21	21	21	21	21	21	21	21	21	231
Change to Expense	0	0	0	0	0	0	0	0	0	0	0	0
69KV INTERRUPTING DEVICE	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	Total
Present Expense	61	61	61	61	61	61	61	61	61	61	61	671
Recommended Expense	118	118	118	118	118	118	118	118	118	118	118	1,298
Change to Expense	57	57	57	57	57	57	57	57	57	57	57	627
12KV INTERRUPTING DEVICE	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	Total
Present Expense	952	952	952	952	952	952	952	952	952	952	952	10,472
Recommended Expense	1,837	1,837	1,837	1,837	1,837	1,837	1,837	1,837	1;837	1,837	1,837	20,207
Change to Expense	885	885	885	885	885	885	885	885	885	885	885	9,735
SWITCH, HV	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	Total
Present Expense	150	150	150	150	150	150	150	150	150	150	150	1,650
Recommended Expense	150	150	150	150	150	150	150	150	150	150	150	1,650
Change to Expense	0	0	0	0	0	0	0	0	0	0	0	0
DC EQUIPMENT	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	Total
Present Expense	213	213	213	213	213	213	213	213	213	213	213	2,343
Recommended Expense	213	213	213	213	213	213	213	213	213	213	213	2,343
Change to Expense	0	0	0	0	0	0	0	0	0	0	0	0
MISCELLANEOUS DEVICE	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	Total
Present Expense	4,207	4,207	4,207	4,207	4,207	4,207	4,207	4,207	4,207	4,207	4,207	46,277
Recommended Expense	4,264	4,264	4,264	4,264	4,264	4,264	4,264	4,264	4,264	4,264	4,264	46,904
Change to Expense	57	57	57	57	57	57	57	57	57	57	57	627
Total Dist Acnt	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	Total
Present Expense	17,955	18,217	18,318	18,437	18,616	18,712	18,822	19,019	19,228	19,425	19,528	206,277
Optimized Expense	28,222	28,441	28,606	28,669	28,879	28,709	28,733	28,828	28,926	28,979	29,049	316,041
Change to Expense	10,267	10,224	10,288	10,232	10,263	9,997	9,911	9,809	9,698	9,554	9,521	109,764

All of the cost estimates presented in this report are in current year dollars, and were not escalated in the cost projections.

Additional Maintenance Cost Exposure - not included in the summary above.

The Distribution line sub-team has proposed replacing equipment that is prone to failure *(as indicated on the health assessment charts in this report) while completing* other work on a pole or at an underground location. Replacing these items, while at the job location, over the next ten years should reduce the risk of exponential growth of outages and the associated deterioration of the reliability indices ($550 per pole average cost, 4090 poles/ year, results in $2.25M per year for the 2010 -2020 span)

Distribution Expense	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	Total $M
Replace while there	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	24.8

Appendix B

Industry Benchmarking Values Typical End of Life, Time between Maintenance, and Mid-Life Failure Rate

The table presented in this appendix is based on Kinectrics experience, and their interpretation of industry experience. It tabulates the typical end of life (EOL) for each asset category. Where known and/or applicable, it provides typical time-based maintenance (TBM); and refurbishment intervals; and equipment failure rates at mid-life.

PPL Expected Life for the various Asset Classes has been added to the table for comparison.

While this represents good benchmarking data, and is the best available on short notice, there are 2 concerns with trying to compare this information with the PPLE T&D system. First the equipment in this table generally represents distribution system equipment. Second, the categories Kinectrics used are not defined.

Note:
PPL Expected Life: The sub-teams reviewed the average age, the maximum age, any recommended values of expected or design life provided by manufacturers, and the general condition of the equipment to estimate the "PPL Expected Life" used in the analysis of the aging assets.

Kinectrics Extreme End of Life: This term has not been defined by Kinectrics.
Kinectrics End of Life: This term has not been defined by Kinectrics. It appears in 4 different documents that PPL has reviewed, and it is used as a general term in all cases. It appears to be an indication that they expect the useful life to have been exhausted, but not that a failure is imminent. It is not tied to in-service failures.

Kinectrics Maintenance and Refurbishment: The distinction between these activities is also not defined, so the team has assumed that a refurbishment would be a major component replacement (life extension) type of project. Maintenance would be the typical preventive and corrective activities.

Kinectrics Equipment Failure Rates at Mid-Life: This term is also not defined, so the team has assumed that Kinectrics presumes that all equipment groups will experience failures in accordance with a traditional bathtub curve. This failure rate is the rate to be expected at the bottom (the flat portion) of the curve.

Apparently, Kinectrics did not provide information on transmission equipment.

Table B.1. Kinectrics Evaluation (with PPL expected life)

Asset Category	*PPL EL [years]*	*Median EOL [years]*	*Extreme EOL [years]*	*TBM Routine [years]*	*TBM Refurbish [years]*	*Mid Life Failure Rate fraction/year*
Station Transformers	60	50	85	3	40	0.001
Circuit Breakers	50	60	75	3	30	0.003
Switchgear Assemblies	NA	50	90	6	30	0.001
Buildings	NA	50	100	1	20	
Network Trans./Protectors	50	35	70	5	15	0.001
Pole Mounted Transformers	40	30	60	NA		0.05
Submersible Transformers	50	25	40	NA		0.07
Vault Transformers	50	40	60	NA		0.05
Pad Mounted Transformers	50	30	50	NA		0.004
Concrete Poles	NA	60	80	15	40	0.0002
Wood Poles	60	50	80	15	40	0.0002
Overhead Switches – *Remote Operated*	40D 50S	40	50	2	10	0.01
Overhead Switches – Manual	40D 50S	40	60	2	10	0.001
Pad Mounted Switchgear	35	40	60	3	15	0.004
Automatic Transfer Switches	NA	30	50	3	15	0.03
Underground Cable – XLPE in Ducts	40	40	60	NA		0.02/km
Underground Cable – PILC in Ducts	70	75	90	NA		0.005
Underground Cable – XLPE Direct Buried	30	25	40	NA		0.04/km
Network Vaults	50	60	80	10	30	0.009
Cable Chambers	NA	60	80	10	30	0.007
OH Line	50-60	60	85	3	40	0.15/km
UG Splice	*30*	*40*	*60*	*NA*		*0.0006*
UG elbow	30	40	60	NA		0.0006
UG cable termination	50	40	60	NA		0.003
Station bus	50S	60	100	NA		0.007
OH Line Recloser	40	40	60	10	NA	0.01
Fuse	40	40	60	NA		0.002
OH Conductor	50-60	60	85	NA		
Capacitors	50D	40	60	NA		
OH Secondary line	40-50	60	80	NA		
UG Secondary Line	40-50	40	60	NA		
Conduit direct buried	50	50	75	NA		

Asset Category	*PPL EL [years]*	*Median EOL [years]*	*Extreme EOL [years]*	*TBM Routine [years]*	*TBM Refurbish [years]*	*Mid Life Failure Rate fraction/year*
Conduit concrete encased	50	80	120	NA		
Pads and bases	50	60	80			
Junction cabinets/boxes	NA	40	50	5	NA	
Station Batteries	20	21	30	1	NA	

Appendix C

Performance Data Requirements for Detailed Assessment Studies

PPLE has contracted with Kinectrics to do condition assessment study of the substation circuit breakers on the T&D system. As a part of the MOS initiative, we also asked them to provide a listing of the data requirements they utilize for a detailed performance analysis. The tables in this appendix were provided by Kinectrics. The data requirements (recommended condition parameters) are broken down by Asset Class and are prioritized based on Kinectrics perception as 'Very Important', 'Important', 'Less Important', and Not Applicable. The tables indicate this priority by color code and the number of asterisks (***).

These tables are based on a summary of Kinectrics experience in Asset Condition Assessment studies and equipment assessment methodology for many utilities. As such, they are the recommended condition parameters that Kinectrics would use, if we were to contract the study to them. The list of PPL data requirements provided in Section 2.6 was developed independently.

Table A Major Asset Categories in Transmission and Distribution Systems

Group	Asset category	Sub-set
1	Substation/network transformers	Transformers without LTC
		Transformers with LTC
		Network transformers & protectors
2	Distribution transformers	Pole mounted transformers
		Pad mounted transformers
		Vault transformers
3	Circuit breakers	Air-blast type circuit breakers
		Oil type circuit breakers
		SF6 type circuit breakers
		Vacuum type circuit breakers
		Air magnet type circuit breakers
4	Switches	
5	Switchgears	Air-insulated switchgears
		Oil-filled switchgears
		SF6-insulated switchgears
6	Overhead conductors	Transmission line conductors
		Distribution line conductors
7	Structures	Wood poles
		Steel poles
		Towers
8	Cables	HPFF/LPFF cables
		XLPE cables
		PILC cables
9	Batteries	
10	Relays	Electromechanical relays
		Solid-state relays
		Digital relays

The MOS team recommends that the data requirements listed in these tables, supplemented with the requirements established by PPL equipment specialists, form the basis of the required data to be used in the future by the PPL team that will do more detailed equipment condition assessments. When this level of detail is available, individual devices (S/N) can be analyzed and compared to one another for prioritization of maintenance or replacement.

Substation/Network Transformers

Table B Group 1 Substation / Network Transformers

#	Substation/network *Transformers* Asset Conditions	Transformers *without LTC*	Transformers *with LTC*	Network *Transformers &* Protectors
1	Bushing Condition	**	**	*
2	Oil Leaks	*	*	*
3	Oil Level	*	*	*
4	Infra-red thermography	***	***	X
5	Cooling	**	**	X
6	Main Tank Corrosion	*	*	X
7	Oil Conservator Corrosion	*	*	X
8	Foundation	*	*	X
9	Grounding	*	*	X
10	Gaskets, seals	*	*	X
11	Connectors	*	*	X
12	Protector Fuse	X	X	*
13	Protector Relay Failure	X	X	*
14	Protector Contacts	X	X	*
15	Overall Condition	**	**	**
16	DGA Oil Analysis	***	***	X
17	Age	**	**	**
18	Winding Doble Test	***	***	X
19	Oil Quality Test	***	***	***
20	Loading (weighted average)	***	***	***
21	Tap changer DGA oil analysis	X	**	X
22	Tap changer oil quality test	X	**	X

#	Substation/network Transformers Asset Conditions	Transformers without LTC	Transformers with LTC	Network Transformers & Protectors

*** very important
** important
* less important
X N/A or has little contribution to Health Index

Distribution Transformers

Table C Group 2 Distribution Transformers

#	Distribution Transformers Asset Conditions	Pole-mounted Transformers	Pad-mounted Transformers	Vault Transformers
1	Infra-red thermography	X	**	***
2	Corrosion	X	*	*
3	Overall Condition	*	*	*
4	Age	***	***	***
5	Rated voltage and capacity	**	**	**
6	Loading (weighted average)	**	**	**

*** very important
** important
* less important
X N/A or has little contribution to HI

Circuit Breakers

Table D Group 3 Circuit Breakers

#	Circuit Breakers Asset Conditions	Air-blast	Oil	SF6	Vacuum	Magnet
1	Age	*	*	*	*	*
2	Life time operating cycles	**	**	**	*	**
3	Rated voltage & current	**	**	**	*	**
4	Operating mechanism type	***	***	***	***	***
5	Static Contact resistance (uOhm)	***	***	***	**	***
6	Arcing contact length (%)	**	**	**	X	X
7	Main contact closing time (cycle)	***	***	***	**	***
8	Average closing velocity (ft/s)	***	***	***	**	***
9	Overtravel distance (inch)	***	***	***	**	***
10	Main contact tripping time (cycle)	***	***	***	**	***
11	Average tripping velocity (ft/s)	***	***	***	**	***

#	Circuit Breakers Asset Conditions	Air-blast	Oil	SF6	Vacuum	Magnet
12	Main contact trip-free time (cycle)	***	***	***	**	***
13	Bushing power dissipation factor (%)	**	**	**	X	X
14	CB Doble test power factor (%)	**	**	**	**	**
15	Dewpoint measurement (degree)	**	X	**	X	X
16	CB operating counter (cycle)	**	**	**	*	**
17	Air pressure (normal/abnormal)	**	X	X	X	X
18	SF6 pressure (normal/abnormal)	X	X	**	X	X
19	Oil level (normal/abnormal)	X	**	X	X	X
20	Oil quality	X	***	X	X	X
21	SF6 analysis	X	X	***	X	X
22	Leakage	*	*	*	X	X
23	Moisture	*	X	*	X	X
24	Lubrication	***	***	***	***	***
25	Mechanism linkage	***	***	***	***	***
26	CB contact	**	**	**	**	**
27	Bushing	*	*	*	X	X
28	Tank/vacuum bottle/arc chute	*	*	*	**	**
29	Control/mechanism cabinet	*	*	*	*	*
30	Supporting insulator	*	*	*	*	*
31	Grading capacitor	*	*	*	X	X
32	Shunt resistor for breaking	*	*	*	X	X
33	Pre-inserted resistor for closing	*	*	*	X	X
34	IR thermography detection	**	**	**	**	**
35	Fault level at CB	*	*	*	*	*
36	CB loadings (weighted average)	**	**	**	**	**

*** very important

** *important*

* less important

X N/A or has little contribution to HI

Switches

Table E Group 4 Switches

#	Switches Asset Conditions	
1	Age	**
2	Rated voltage & current	*
3	Operating mechanism type	***
4	Mechanism linkage	***
5	Arc horn	**
6	Fuse	*
7	Switch contact	**
8	Lubrication	***
9	Support insulator	*
10	Switch motor	**
11	Control cabinet	*
12	Overall condition	**
13	IR thermography	***
14	Loading (weighted average)	**
15	Overall condition	**

*** very important
** important
* less important

Switchgear

Table F Group 5 Switchgear

#	Switchgear Asset Conditions	Air-insulated	Oil-filled	SF6-insulated
1	Age	*	**	*
2	Life time operating cycles	**	***	**
3	Rated voltage & current	**	**	**
4	Contactor type	***	***	***
5	Operating mechanism	***	***	***
6	Pressure	X	X	**
7	Protection alarm	*	*	*
8	Oil quality	X	***	X
9	Busbar	**	**	*
10	Cabling	*	*	*
11	Arc proof duct	**	X	X
12	Lubrication	***	***	***
13	Contactor	***	***	***
14	Fuse	*	*	*
15	CT & PT	*	*	*
16	Grounding switch	*	*	*
17	Gaskets & sealing	X	*	*
18	Metal enclosure	*	*	*
19	Motor	**	**	**
20	IR thermography detection	***	***	***
21	Overall condition	**	**	**

*** very important
** important
* less important
X N/A or has little contribution to HI

Overhead Conductors

Table G Group 6 Overhead Conductors

#	Overhead conductors Asset Conditions	Transmission line conductors	Distribution line conductors
1	Conductor problem	**	**
2	Conductor other hardware problem	*	*
3	Shield wire problem	**	X
4	Shield wire other hardware problem	*	X
5	Insulator damage	*	*
6	Insulator flashover	*	*
7	Insulator contamination	*	*
8	Arrester	X	*
9	Conductor torsional ductility (sample test)	***	X
10	Conductor tensile/elongation (sample test)	***	X
11	Conductor Aeolian vibration (sample test)	***	X
12	Conductor remaining zinc (sample test)	**	X
13	Resistance	**	**
14	Age	**	**
15	Overall condition	***	***
16	Outage record (yearly for years)	***	***
17	Loading (weighted average)	**	**

*** very important
** important
* less important
X N/A or has little contribution to HI

Structures

Table H Group 7 Structures

#	Structures Asset Conditions	Wood Poles	Steel Poles	Towers
1	Pole strength (test)	***	X	X
2	Pole crack/woodpecker/decay	**	X	X
3	Cross arm	**	X	X
4	Accessory hardware	*	*	*
5	Structure grounding	*	*	X
6	Structure foundation	*	*	*
7	Steel member bent/damaged	X	**	**
8	Steel deterioration due to rust	X	**	**
9	Overall condition	**	**	**
10	Age	***	***	***
11	Restoration date	***	X	X

*** very important
** important
* less important
X N/A or has little contribution to HI

Cables

Table I Group 8 Cables

#	Cables Asset Conditions	HPFF/LPFF type	XLPE type	PILC type
1	Cable splice problem	*	*	*
2	Dc hi-pot	*	X	*
3	Gasket joint failure	*	*	*
4	Oil leak	**	X	**
5	Oil pressure	**	X	**
6	Pumping plant problems	**	X	X
7	Oil DGA	***	X	***

8	Oil quality	**	X	**
9	Cable failure rate	***	***	***
10	Loading (weighted average)	**	***	**
11	Age	*	***	**
12	Overall condition	**	**	**

*** very important
** important
* less important
X N/A or has little contribution to HI

Batteries

Table J Group 9 Batteries

#	Batteries Asset Conditions	
1	Cell replacement	**
2	Charger	*
3	Corrosion	*
4	DC ground	*
5	IR thermography	**
6	Battery impedance	**
7	Electrolyte level	**
8	Connection	*
9	Equalizing charge	**
10	Storage temperature	***
11	Battery capacity %	***
12	Specific gravity	**
13	Float current	**
14	Cell voltage	**
15	AC ripple	*
16	Age	***

#	Batteries Asset Conditions	
17	Cell replacement %	**
18	Number of discharge cycles	**

*** very important
** important
* less important

Relays

Table K Group 10 Relays

#	Relays Asset Conditions	Electromechanical type	Solid-state type	Digital type
1	Contact	***	X	X
2	Coil	**	X	X
3	Spring	*	X	X
4	Power supply	X	**	**
5	Insulation	*	*	*
6	Connection	*	*	*
7	Component replace	**	*	X
8	Card replace	X	**	X
9	Device replace	X	X	***
10	Harmonics	**	*	X
11	Temperature	**	**	X
12	Moisture	**	**	X
13	Vibration	*	*	X
14	Calibration record	***	***	X
15	*Operating count*	*	*	*
16	Loading	*	*	X
17	Age	*	*	*
18	Overall condition	**	**	**

*** very important
** important

#	Relays Asset Conditions	Electromechan ical type	Solid-state type	Digital type

* less important
X N/A or has little contribution to HI

Appendix D: Detailed Approach to Condition Assessment

An Example of the detail required for Future Assessment Programs
A thorough condition assessment approach would have required the team to look at a large collection of data, inspect the equipment, and do a detailed analysis. Nearly all proposals from manufacturers or consulting engineering firms will be based on this type of condition assessment.

The extent of the investigation would be determined by the type of condition assessment planned. The list of acceptable recommendations that result from the study should always be used to determine the depth and breadth of the study that is required.

For example- If the outcomes to be evaluated include:

- Perform routine preventive maintenance,
- Perform corrective maintenance,
- Perform a "life extension" refurbishment project on site,
- Perform a "life extension" refurbishment project in a repair shop,
- Perform capital replacement of all known equipment prone to premature failure on specific circuits,
- Replace (If replaced, remanufacture or scrap)

Then a detailed analysis of all available data for all of the components, and ancillary devices is required.

At the other extreme, if the outcomes to be evaluated include only

- Retain in-service and continue maintenance
- Replace (If replaced, remanufacture or scrap)

In this case, a different analysis is required. Here any test or inspection that leads to a maintenance recommendation should be skipped. Only the analysis of long term degradation is relevant.

However, in most proposals from outside contractors, this is not effectively addressed. A quick review of the data requirements provided by Kinectrics shows that many of the criteria are affected by routine maintenance activities. Therefore, if PPL adopts the data requirements provided by Kinectrics, we would be structuring our condition assessment program similarly to the first example. Therefore, recommendations for maintenance should be an acceptable us assessment is outdated and invalid; therefore, a new assessment is required, and expected outcome. Obviously, once the maintenance is performed, the previous assessment is outdated and invalid. A new assessment is required. This type of assessment program requires continuous, computerized updating of the condition assessments.

Examples of expected future assessments at PPL- This type of assessment was not done as a part of the MOS study.

If we did a detailed evaluation of typical distribution pole, we would have looked at:

- Pole inspection results
- Date of installation
- Maintenance Records
- Ancillary devices – Transformers, sectionalizing devices, primary secondary conductors, pole line hardware, etc.
  - Each of these devices would need to be analyzed based on maintenance testing records and inspection history results. In addition, industry experience with them would provide assistance in establishing an expected life for theses components.

These, and perhaps other, criteria would have been evaluated to develop a health index for that particular pole location. The distribution facilities would have been evaluated to determine which of the units are critical to the operation of the overall distribution system, and which have little or no impact on the system. Then when all of the various important units were evaluated, PPL could have plotted a criticality vs. health chart to establish an overall condition assessment of the installed distribution equipment, and to establish the priority of a particular S/N unit for preventative or capital replacement.

As another example, if we did a detailed evaluation of power transformers, we would have looked at:

- Oil quality test results
- DGA (oil) test results
- Doble test results
- Maintenance Records
- Loading history records
- Age
- Manufacturer's Design issues
- Ancillary devices – Bushings, tap changers, gauges, control systems, etc.
  - Each of these devices would need to be analyzed based on maintenance records testing and inspection history results. In addition, industry experience with them would provide assistance in establishing an expected life for theses components.

These, and perhaps other, criteria would have been evaluated to develop a health index for that particular S/N transformer. The substations would have been evaluated to determine which of the units are critical to the operation of the system, and which have little or no impact on the system. Then when all of the various important units were evaluated, PPL could have plotted a criticality vs. health chart to establish an overall condition assessment of the fleet, and to establish the priority of a particular S/N unit for refurbishment or replacement.

Since the PPL team was tasked with working part time on a 6 – 8 week project to do condition assessments, develop a capital replacement program to offset the effects of the aging infrastructure, and to propose an optimized maintenance plan, it would have been impossible to do the detailed level of assessment described above. If

PPLE determines that assessments at this level of detail are required, another team of dedicated, knowledgeable persons would need to be assigned to take the time do this type of work. Of course, that presumes that changes are made so that PPL begins to collect and maintain the supporting information.

Appendix E: PA PUC Inspection & Maintenance Standards

As an outcome from the 1997 Electric Generation and Customer Choice Competition Act, the PA Legislature instructed the PA PUC to monitor reliability performance among PA electric distribution companies (EDCs) and institute controls where needed to ensure reliability performance occurring before deregulation did not degrade following deregulation.

In 2008, the PA PUC adopted final form regulations designed to improve reliability performance for PA EDCs by requiring EDCs to file biennial inspection and maintenance plans with the PA PUC. PPL Electric must file its first biennial plans on or before October 1, 2010. The regulations have also established inspection and maintenance standards for a variety of activities as depicted in Table E5.

Table E5.

I&M Activity	Regulation	Our Current Practice
Vegetation Management	4-8 yr.	Rural 6 yr.; Urban 4 yr.
Pole Inspections	1st: SYP 25 yr.; Other 12 yr. Subsequent: 10-12 yr.	1st: SYP 25 yr.; Other 10 yr. Subsequent: 1-9 yr.
OH Line Inspections	1-2 yr.	No fixed interval; performance based; ≈18% of lines annually
OH Dist. Transf.	OH 1-2 yr.	No fixed interval
UG Dist. Transf.	Pad-mt. 5 yr.; Submersible 8 yr.	No fixed interval
OCR	3∅ 8 yr.; 1∅ 1-2 yr.	10 yr. replacement cycle
Substations	5 weeks	SCADA 1 yr.; non SCADA 3 mo.

EDCs may propose alternatives to the prescribed standards, provided the deviations can be justified by the EDC's unique circumstances, or by a cost/benefit analysis supporting an alternate approach that will still support the levels of reliability performance required by law. It is therefore in PPL Electric's best interest to make the right operating decisions regarding its inspection and maintenance practices and justify these to the PA PUC.

To accomplish this task, a team will be formed during the 3rd quarter of 2009 to develop the strategy associated with biennial plan filings for the mandated inspection and maintenance activities as they related to PPL Electric's current and future operational practices, including financial and regulatory implications. Given the timing of this activity, the MOS teams did not specifically incorporate the PA PUC inspection and maintenance standards in their respective analyses. It is anticipated, however, that certain MOS team members will be contributors to the development of PPL Electric's biennial inspection and maintenance plans, thereby ensuring continuity between these two efforts.

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PPL Electric Utilities Corporation
Response to Data Request of the
Office of Technical Utility Services, Set I
Dated October 15, 2012
Docket No. P-2012-2325034

Q.TUS-P-2. Regarding the cost effectiveness of the LTIIP, addressed in paragraphs 21-23 of the Petition, provide additional information, including calculations and tabulated summaries, that show the benefits, including avoided costs, for the specific planned infrastructure repairs and replacements in the LTIIP. Relate this information to PPL Electric's most recently filed Biennial Report.

A.TUS-P-2. PPL Electric routinely reviews the effectiveness of programs to ensure cost-effective investment. Program/project impact on SAIDI and SAIFI, in addition to potential reductions in outage response costs, are compared to the overall program/project costs. PPL Electric utilizes a project prioritization process that defines the cost-effectiveness of programs/projects to ensure effective optimization of reliability investments.[1] The optimal selection for program funding is more complex than simply funding the highest returning CMI per dollar program, then the second highest, etc. until funds are exhausted. The optimal program mix must consider regulatory requirements, program synergy, short and long term reliability, safety, customer satisfaction and other factors.

CMI/CI (Customer Interruptions) savings represent avoidance of potential and likely CMI/CI not yet incurred, not necessarily a reduction from the previous year's CMI/CI. This estimate is based on the historical consequence of a mitigated service interruption and the probability of a similar event occurring in the absence of the program.

For purposes of producing savings calculations, each program is evaluated as if it were the only program being implemented to produce a relative ranking. For example, adding a telemetric recloser to a circuit might be scored as saving X CMI based on the history of service interruptions on that circuit. A reconductoring project on the same circuit might be scored as saving Y CMI. However, doing both projects would not necessarily save X+Y CMI due to some amount of overlap. Therefore, estimated CMI/CI savings are not additive and should be considered independently for each program. A partial sample of one such calculation is included as TUS-P-2 Attachment 1.

Inspections done under the Biennial Plan can identify failing conditions which

[1] For example, a weakened pole would be evaluated for potential fiber wrapping, c-trussing, or replacement. The lowest cost alternative that returns the pole to 100% strength would be employed. Similarly, cable curing may be chosen as more cost effective than replacement, but may not always be feasible.

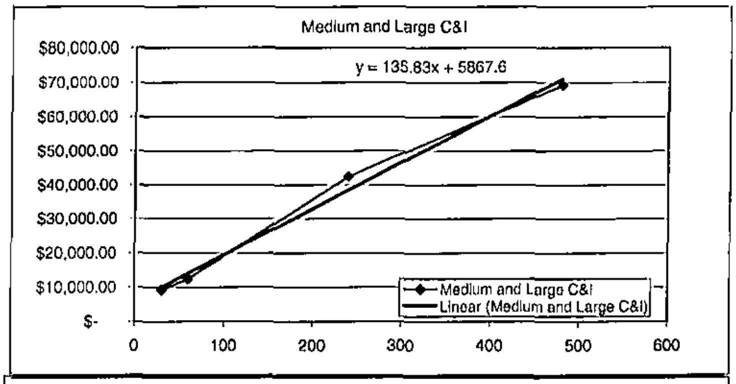
may be remediated under the Long Term infrastructure Improvement Plan. However, the Biennial Plan addresses the inspection and maintenance activities of a utility, not capital expansion activity. Once maintenance inspection of a facility identifies a capital need, the construction project would not be reflected in the Biennial Plan, but rather would be reflected in the LTIIP.

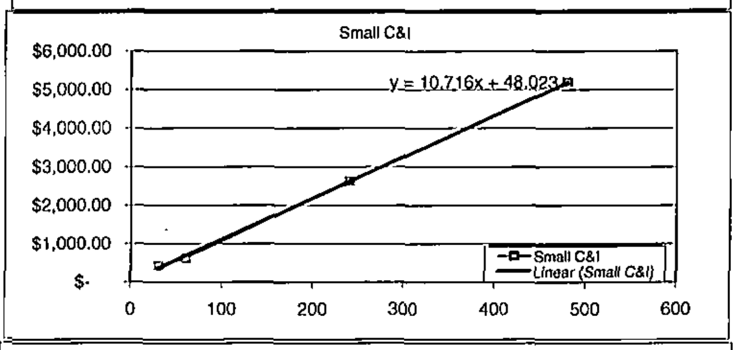
See TUS-P-2 Attachment 2 for the CMI, CI and cost chart.

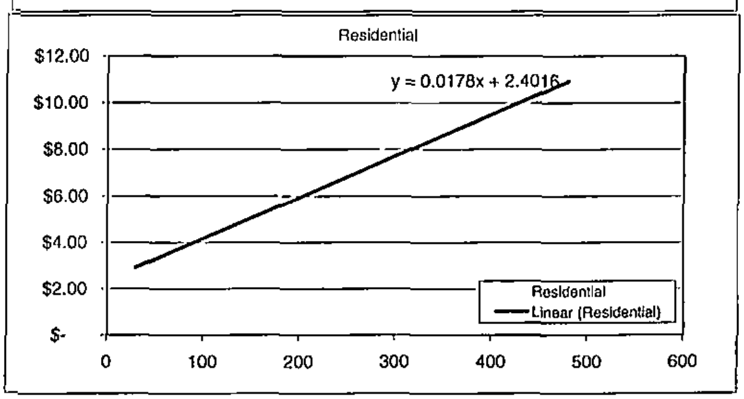
PPL Electric Utilities Corporation

From DOE Report LBNL-2132E - Estimated Value of Service Reliability for Electric Utility Customers in the United States
Page xxv1, Table ES-5
Customer Interruption Costs US 2008$ Anytime By Duration and Customer Type

Interruption Cost	Interruption Duration - Minutes: Momentary	30	60	240	480	Linear Fit a + b*x: a	b	crossover point in minutes	mimimum outage cost
Medium and Large C&I									
Cost Per Event	$ 6,558.00	$ 9,217.00	$ 12,487.00	$ 42,506.00	$ 69,284.00	$ 5,867.60	$ 135.80	5.08	$ 6,558.00
Cost Per Average kW	$ 8.00	$ 11.30	$ 15.30	$ 52.10	$ 85.00				
Cost Per Un-served kWh	$ 96.50	$ 22.60	$ 15.30	$ 13.00	$ 10.60				
Cost Per Annual kWh	$ 0.000918	$ 0.001290	$ 0.001750	$ 0.005950	$ 0.009700				
Small C&I									
Cost Per Event	$ 293.00	$ 435.00	$ 619.00	$ 2,623.00	$ 5,195.00	$ 48.02	$ 10.70	22.90	$ 293.00
Cost Per Average kW	$ 133.70	$ 198.10	$ 282.00	$ 1,195.80	$ 2,368.60				
Cost Per Un-served kWh	$ 1,604.10	$ 396.30	$ 282.00	$ 298.90	$ 296.10				
Cost Per Annual kWh	$ 0.015300	$ 0.022600	$ 0.032200	$ 0.137000	$ 0.270000				
Residential									
Cost Per Event	$ 2.10	$ 2.70	$ 3.30	$ 7.40	$ 10.60	$ 2.40	$ 0.02	(16.85)	$ 2.40
Cost Per Average kW	$ 1.40	$ 1.80	$ 2.20	$ 4.90	$ 6.90				
Cost Per Un-served kWh	$ 16.80	$ 3.50	$ 2.20	$ 1.20	$ 0.90				
Cost Per Annual kWh	$ 0.000160	$ 0.000201	$ 0.000246	$ 0.000558	$ 0.000792				







PPL Electric Utilities Corporation

Outage Year	Feeder	SG II Project	Job Number	Trouble Date & Time	Restore Date & Time	Duration	Event Indicator	Customers	Cust Int - Perm	CMI	SAIFI
2005	10502	North Lehigh	154423	8/16/2005 09:04:00 AM	8/16/2005 10:06:00 AM	62	N	1,109	399	24,738	0.36
2005	10502	North Lehigh	155023	10/12/2005 03:40:00 PM	10/12/2005 04:23:00 PM	43	N	1,109	789	38,661	0.71
2005	10502	North Lehigh	153828	12/10/2005 09:36:00 AM	12/10/2005 10:02:00 AM	26	N	1,109	789	20,514	0.71
2005	10504	North Lehigh	153135	5/28/2005 03:09:00 PM	5/28/2005 03:27:00 PM	18	N	1,045	283	5,094	0.27
2005	10504	North Lehigh	153135	5/28/2005 03:09:00 PM	5/28/2005 08:03:00 PM	294	N	1,045	752	221,088	0.72
2005	10504	North Lehigh	153149	5/29/2005 08:23:00 AM	5/29/2005 08:55:00 AM	32	N	1,045	1	32	0.00
2005	10504	North Lehigh	153168	5/31/2005 07:01:00 AM	5/31/2005 10:30:00 AM	209	N	1,045	1	209	0.00
2005	10504	North Lehigh	158392	3/12/2005 01:33:00 AM	3/12/2005 11:15:00 AM	582	N	1,045	1	582	0.00
2005	10602	Lehigh	170617	3/23/2005 09:24:00 AM	3/23/2005 12:01:00 PM	157	N	1,972	42	6,594	0.02
2005	10602	Lehigh	170722	5/1/2005 09:43:00 AM	5/1/2005 11:02:00 AM	79	N	1,972	1,966	155,314	0.99
2005	10602	Lehigh	171054	7/4/2005 02:40:00 PM	7/4/2005 06:25:00 PM	225	N	1,972	156	35,100	0.07
2005	10602	Lehigh	171624	11/10/2005 09:01:00 AM	11/10/2005 10:58:00 AM	117	N	1,972	410	47,970	0.20
2005	10702	North Lehigh	154479	8/21/2005 07:42:00 AM	8/21/2005 01:30:00 PM	348	N	1,851	1	348	0.00
2005	10702	North Lehigh	166128	10/4/2005 09:05:00 AM	10/4/2005 10:28:00 AM	83	N	1,851	867	71,961	0.46
2005	10702	North Lehigh	166128	10/4/2005 09:05:00 AM	10/4/2005 11:13:00 AM	128	N	1,851	30	3,840	0.01
2005	10702	North Lehigh	166128	10/4/2005 09:05:00 AM	10/4/2005 09:15:00 PM	730	N	1,851	36	26,280	0.01
2005	10702	North Lehigh	166658	12/5/2005 01:46:00 PM	12/5/2005 03:03:00 PM	77	N	1,851	919	70,763	0.49
2005	10702	North Lehigh	166658	12/5/2005 01:46:00 PM	12/5/2005 03:15:00 PM	89	N	1,851	946	84,194	0.51
2005	10703	North Lehigh	165025	6/6/2005 03:11:00 PM	6/6/2005 04:05:00 PM	54	Y	586	531	28,674	0.90
2005	10703	North Lehigh	165025	6/6/2005 03:11:00 PM	6/6/2005 05:30:00 PM	139	Y	586	50	6,950	0.08
2005	10703	North Lehigh	165025	6/6/2005 03:11:00 PM	6/6/2005 06:37:00 PM	206	Y	586	6	1,236	0.01
2005	10703	North Lehigh	165025	6/6/2005 03:11:00 PM	6/6/2005 07:50:00 PM	279	Y	586	3	837	0.00
2005	10703	North Lehigh	165025	6/6/2005 03:11:00 PM	6/7/2005 01:15:00 AM	604	Y	586	1	604	0.00
2005	10703	North Lehigh	165070	6/6/2005 08:53:00 PM	6/6/2005 11:25:00 PM	152	Y	586	1	152	0.00
2005	10703	North Lehigh	165077	6/7/2005 06:55:00 AM	6/7/2005 10:00:00 AM	185	N	586	1	185	0.00
2005	10703	North Lehigh	165330	7/2/2005 12:33:00 AM	7/2/2005 01:25:00 AM	52	N	586	60	3,120	0.10
2005	10703	North Lehigh	165905	9/1/2005 06:02:00 AM	9/1/2005 09:40:00 AM	218	N	586	1	218	0.00
2005	10901	Lehigh	164873	5/16/2005 02:59:00 AM	5/16/2005 03:45:00 AM	46	N	525	1,470	67,620	2.80

- Partial sample, for illustrative purposes only.

			Manual Sectionalizing Only			Automatic Sectionalizing Only			Auto vs Manual							Fault locating				Customer Breakdown			
SAIDI	CAIDI	Pot Cust Min	Man. Sectionalized	Avoided CMI	Pct Avoided CMI	Auto. Sectionalized	Avoided CMI	Remaining CMI	Improved CMI	Pct Improved CMI	Avoided Customer Interrupts	Avoided Minutes per Avoided CI	Value of Avoided Minutes	Cost of Addl Momentaries (former CI's)	Total Value of Auto Sectionalizing	Avoided Minutes per Remaining CI	Avoided CMI from fault locating	Value of Avoided Minutes	Avoided Mhrs from fault locating	Res	Sm I&C	Lg I&C	Total
22.307	62	24738	FALSE	0	0%	TRUE	1,488	23,250	1,488	6%	24	62	$ 5,466	$ 4,083	$ 1,383	6.2	2,325	$ 9,502	0.5	85.4%	12.6%	2.0%	100.0%
34.661	43	33661	FALSE	0	0%	TRUE	20,286	13,375	20,286	52%	414	43	$ 51,930	$ 70,434	$ 0	4.3	1,838	$ 7,510	0.5	85.4%	12.6%	2.0%	100.0%
16.493	26	20514	FALSE	0	0%	TRUE	10,764	9,750	10,764	52%	414	26	$ 51,930	$ 70,434	$ 0	2.6	975	$ 3,935	0.5	85.4%	12.6%	2.0%	100.0%
4.875	18	5094	FALSE	0	0%	FALSE	(1,686)	5,094	0	0%	0	0	$ 0	$ 0	$ 0	0.0	0	$ 0	0.0	83.5%	12.5%	4.0%	100.0%
211.567	294	221088	FALSE	0	0%	TRUE	110,838	110,250	110,838	50%	377	294	$ 169,512	$ 114,205	$ 55,307	29.4	11,025	$ 75,301	0.5	83.5%	12.5%	4.0%	100.0%
0.031	32	32	FALSE	0	0%	FALSE	(11,969)	32	0	0%	0	0	$ 0	$ 0	$ 0	0.0	0	$ 0	0.0	83.5%	12.5%	4.0%	100.0%
0.200	209	209	FALSE	0	0%	FALSE	(78,166)	209	0	0%	0	0	$ 0	$ 0	$ 0	0.0	0	$ 0	0.0	83.5%	12.5%	4.0%	100.0%
0.557	582	582	FALSE	0	0%	FALSE	(217,668)	582	0	0%	0	0	$ 0	$ 0	$ 0	0.0	0	$ 0	0.0	83.5%	12.5%	4.0%	100.0%
3.244	157	6594	FALSE	0	0%	FALSE	(52,280)	6,594	0	0%	0	0	$ 0	$ 0	$ 0	0.0	0	$ 0	0.0	89.6%	9.2%	1.2%	100.0%
78.760	79	155314	FALSE	0	0%	TRUE	125,689	29,625	125,689	81%	1,591	79	$ 828,779	$ 168,059	$ 660,720	7.9	2,363	$ 7,676	0.5	89.6%	9.2%	1.2%	100.0%
17.799	225	35100	FALSE	0	0%	FALSE	(49,275)	35,100	0	0%	0	0	$ 0	$ 0	$ 0	0.0	0	$ 0	0.0	89.6%	9.2%	1.2%	100.0%
24.326	117	47970	FALSE	0	0%	TRUE	4,095	43,875	4,095	9%	35	117	$ 2,634	$ 3,697	$ 0	11.7	4,388	$ 11,368	0.5	89.6%	9.2%	1.2%	100.0%
0.188	348	348	FALSE	0	0%	FALSE	(130,152)	348	0	0%	0	0	$ 0	$ 0	$ 0	0.0	0	$ 0	0.0	85.1%	13.1%	1.8%	100.0%
36.677	83	71061	FALSE	0	0%	TRUE	40,836	31,125	40,836	57%	492	83	$ 157,538	$ 77,291	$ 80,247	8.3	3,113	$ 11,943	0.5	85.1%	13.1%	1.8%	100.0%
2.075	128	3840	FALSE	0	0%	FALSE	(44,160)	3,840	0	0%	0	0	$ 0	$ 0	$ 0	0.0	0	$ 0	0.0	85.1%	13.1%	1.8%	100.0%
14.198	730	26280	FALSE	0	0%	FALSE	(247,470)	26,280	0	0%	0	0	$ 0	$ 0	$ 0	0.0	0	$ 0	0.0	85.1%	13.1%	1.8%	100.0%
38.230	77	70763	FALSE	0	0%	TRUE	41,888	28,875	41,888	59%	544	77	$ 61,467	$ 65,460	$ 0	7.7	2,888	$ 11,080	0.5	85.1%	13.1%	1.8%	100.0%
45.428	89	84194	FALSE	0	0%	TRUE	50,819	33,375	50,819	60%	571	89	$ 136,822	$ 89,702	$ 47,120	8.9	3,338	$ 12,807	0.5	85.1%	13.1%	1.8%	100.0%
48.932	54	28674	FALSE	0	0%	TRUE	8,424	20,250	8,424	29%	156	54	$ 188,823	$ 96,688	$ 92,135	5.4	2,025	$ 26,750	0.5	82.4%	8.5%	9.0%	100.0%
11.660	139	6950	FALSE	0	0%	FALSE	(45,175)	6,950	0	0%	0	0	$ 0	$ 0	$ 0	0.0	0	$ 0	0.0	82.4%	8.5%	9.0%	100.0%
2.109	288	1236	FALSE	0	0%	FALSE	(76,014)	1,236	0	0%	0	0	$ 0	$ 0	$ 0	0.0	0	$ 0	0.0	82.4%	8.5%	9.0%	100.0%
1.428	279	837	FALSE	0	0%	FALSE	(103,783)	837	0	0%	0	0	$ 0	$ 0	$ 0	0.0	0	$ 0	0.0	82.4%	8.5%	9.0%	100.0%
1.031	604	604	FALSE	0	0%	FALSE	(225,896)	604	0	0%	0	0	$ 0	$ 0	$ 0	0.0	0	$ 0	0.0	82.4%	8.5%	9.0%	100.0%
0.259	152	152	FALSE	0	0%	FALSE	(56,848)	152	0	0%	0	0	$ 0	$ 0	$ 0	0.0	0	$ 0	0.0	82.4%	8.5%	9.0%	100.0%
0.316	165	165	FALSE	0	0%	FALSE	(69,190)	165	0	0%	0	0	$ 0	$ 0	$ 0	0.0	0	$ 0	0.0	82.4%	8.5%	9.0%	100.0%
5.324	52	3120	FALSE	0	0%	FALSE	(16,380)	3,120	0	0%	0	0	$ 0	$ 0	$ 0	0.0	0	$ 0	0.0	82.4%	8.5%	9.0%	100.0%
0.372	218	218	FALSE	0	0%	FALSE	(81,532)	218	0	0%	0	0	$ 0	$ 0	$ 0	0.0	0	$ 0	0.0	82.4%	8.5%	9.0%	100.0%
128.600	46	67620	FALSE	0	0%	TRUE	50,370	17,250	50,370	74%	1,035	46	$ 35,124	$ 60,288	$ 0	4.6	1,725	$ 2,585	0.5	91.3%	8.2%	0.4%	100.0%

- Partial sample, for illustrative purposes only.

PPL Electric Utilities Corporation

5 Yr Cumulative Savings for Ranking Purposes

Infrastructure Initiative	*CMI Savings*	*CI Savings*	*Maint Savings*
Distribution Pole Replacements	$ 619,989	$ 4,376	$ 500,000
C-Truss Distribution Poles	955,871	6,747	850,000
Fiber Wrap Distribution Poles	486,734	3,436	850,000
Recloser Replacements	38,781,547	269,837	0
Capacitors	0	0	0
New Hydraulic Reclosers	5,059,788	25,011	0
Distribution Animal Guarding	353,764	4,717	570,000
Distribution Failed Equipment	67,345,066	660,246	0
Replace Failed Underground Primary Cable	17,082,500	36,000	0
Replace Failed Underground Secondary Cable	0	0	0
Replace Failed 12kV Underground Getaway Cable	3,300,000	31,000	0
Replace Deteriorated/Failed Low-Tension Network Equipment and Structures	0	0	0
Underground Residental Development Cable Replacement and Life Extension	15,012,591	142,656	7,100,000
Low Tension Network Primary Cable, Equipment and Structures	0	0	750,000
12 kV Underground Getaway Cables	42,182,858	385,918	0
Copper Weld Copper	8,611,273	65,738	0
Customers Experiencing Multiple Interruptions	527,468	7,362	395,000
Distribution Reliability Preservation	3,838,308	6,476	0
Reliability Preservation Emergent	532,814	3,806	0
Circuit SAIDI Improvement	85,940,939	381,868	375,000
Distribution Automation Development	142,600,000	1,490,000	20,000
Improve System Reliability Projects	138,627	929	0
Unreimbursed Highway Relocations	0	0	0
Distribution Substation Circuit Breakers	21,091,442	292,188	440,000
Substation 69/12 kV Transformer Replacement	55,606,266	649,078	890,000
Protection and Control	3,659,012	46,720	0
Cross-Yard 12 kV Underground Tie	1,600,000	10,000	0
Replace Deteriorated/Failed Area Supply Substation Equipment	800,000	5,000	0
Repair Failed 138/69 12 kV Transformers	0	0	0
Distribution Substation DC Equipment	0	0	0
Miscellaneous Substation Equipment	25,553,783	298,284	570,000
Substation Animal Guarding	$ 26,466,440	$ 335,920	$ 0

A more detailed description of each Initiative can be found in the original LTIIP filing.

S.Gelatko

PPL Electric Utilities Corporation
Response to Data Request of the
Office of Technical Utility Services, Set I
Dated October 15, 2012
Docket No. P-2012-2325034

Q.TUS-P-3. The Planned Replacements in Units and Planned Expenditures are provided for each of the 32 distribution assets groups detailed in the LTIIP. Provide the historical data for both replacements and expenditures for these asset groups for at least the previous five years: 2008-2012.

A.TUS-P-3. See TUS-P-3 Attachment 1 for historical replacements and expenditures for each of the asset groups identified in the LTIIP for the period 2008 through 2012 (forecasted). For a number of projects PPL Electric is not able to readily obtain historical data but is working on implementing a methodology to obtain this information moving forward.

PPL Electric Utilities Corporation

LTII PLAN DESCRIPTION	Unit	2008	2009	2010	2011	2012 (*Forecasted*)
Distribution Pole Replacements	# of Poles	2,550	1,588	1,244	1,583	2,126
C-Truss Distribution Poles	# of Poles	429	2,812	5,845	4,342	5,150
Fiber Wrap Distribution Poles	# of Poles					1,100
Recloser Replacements	# of Reclosers	491	253	729	449	644
Capacitors	# of Capacitors	167	106	144	85	80
New Hydraulic Reclosers	# of Reclosers		25	46	41	0
Distribution Animal Guarding	# of Animal Guards		423	296	275	0
Distribution Failed Equipment	Pieces of Equipment					
Replace Failed Underground Primary Cable	*# of Cable Sections*	*151*	*182*	*241*	*276*	*190*
Replace Failed Underground Secondary Cable	# of Cable Sections	224	247	242	303	227
Replace Failed 12kV Underground Getaway Cable	# of UG Getaway Cables	2	3	7	10	8
Replace Deteriorirated/Failed Area Supply Substation Equipment	Pieces of Equipment					
Underground Residental Development Cable Replacement and Life Extension - Replacement after Test	# of Cable Sections	368	259	219	203	244
Underground Residental Development Cable Replacement and Life Extension - Proactive Replacement	# of Cable Sections			115	59	
Underground Residental Development Cable Replacement and Life Extension - Cure	# of Cable Sections	135	308	581	214	400
Low Tension Network Primary Cable, Equipment and Structures - LTN Equipment	Pieces of Equipment					
Low Tension Network Primary Cable, Equipment and Structures - Lead Cable	Miles					
12 kV Underground Getaway Cables	# of UG Getaway Cables			9	32	21
Copper Weld Copper	Miles					
Customers Experiencing Multiple Interruptions	# of Projects			60	30	39
Distribution Reliability Preservation	# of Projects	478	552	665	390	226
Reliability Preservation Emergent	# of Projects	282	140	221	183	356
Circuit SAIDI Improvement	*# of Projects*	*71*	*102*	*170*	*129*	*130*
Distribution Automation Deployment - Substation Equipment	# of Substations				8	2
Distribution Automation Deployment - Devices	# of Devices			180	212	94
System Reliability Improvement Projects	# of Projects				19	16
Unreimbursed Highway Relocations	# of Projects	72	92	79	100	
Distribution Substation Circuit Breakers	# of CB's			30	41	28
Substation 69/12 kV Transformer Replacement	# of Transformers			6	2	7
Protection and Control	# of Projects		4	9		
Cross-Yard 12 kV Underground Ties	# of Projects				2	6
Replace Deteriorated/Failed Low-Tension Network Equipment and Structures	Pieces of Equipment					
Repair Failed 138/69 12 kV Transformers	# of Transformers					
Distribution Substation DC Equipment	# of Projects					42
Miscellaneous Substation Equipment	# of Projects			4	20	
Substation Animal Guarding	# of Substations		27	28	44	22

S.Gelatko

PPL Electric Utilities Corporation
Response to Data Request of the
Office of Technical Utility Services, Set I
Dated October 15, 2012
Docket No. P-2012-2325034

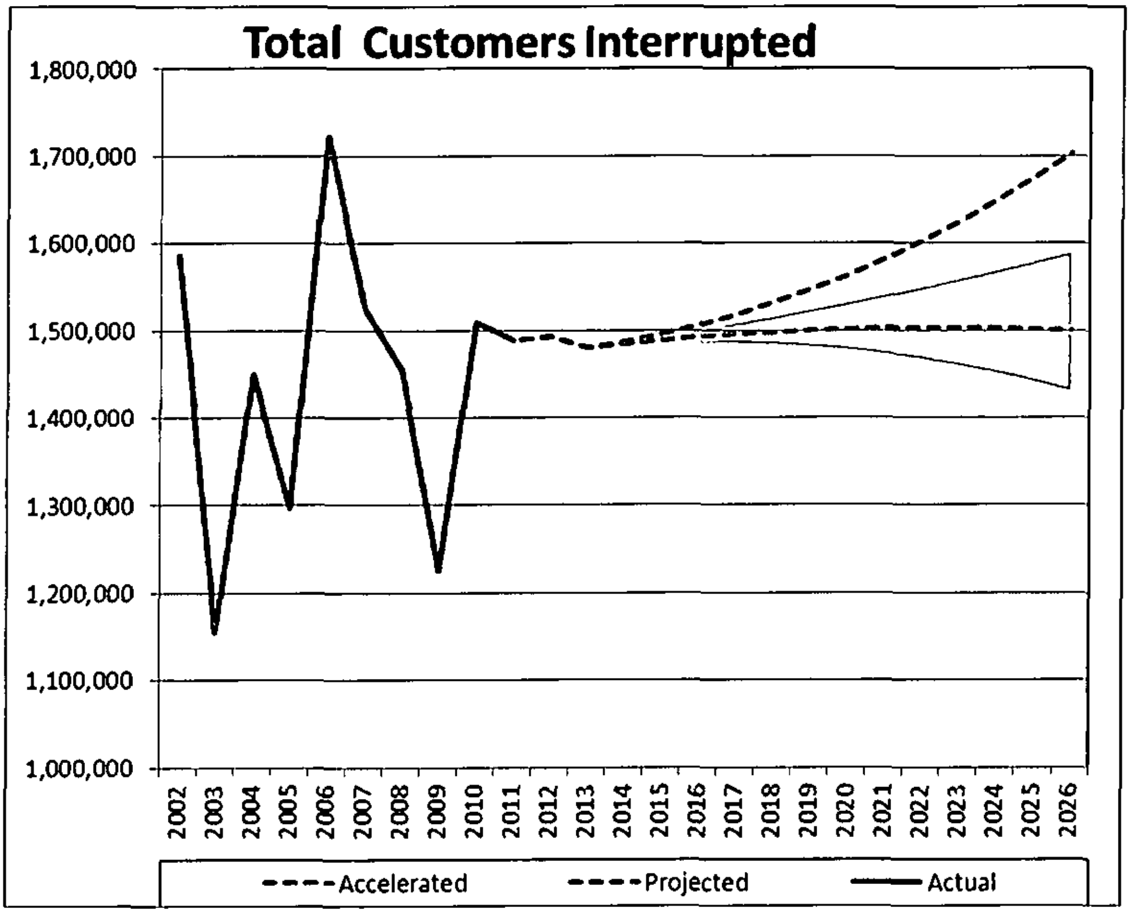
Q. TUS-P-4. Provide additional information showing how the planned improvements outlined in the LTIIP are projected to increase the reliability of PPL Electric's distribution system. Include projected impacts to SAIFI, SAIDI, and CAIDI performance indicators as a result of the distribution system improvements.

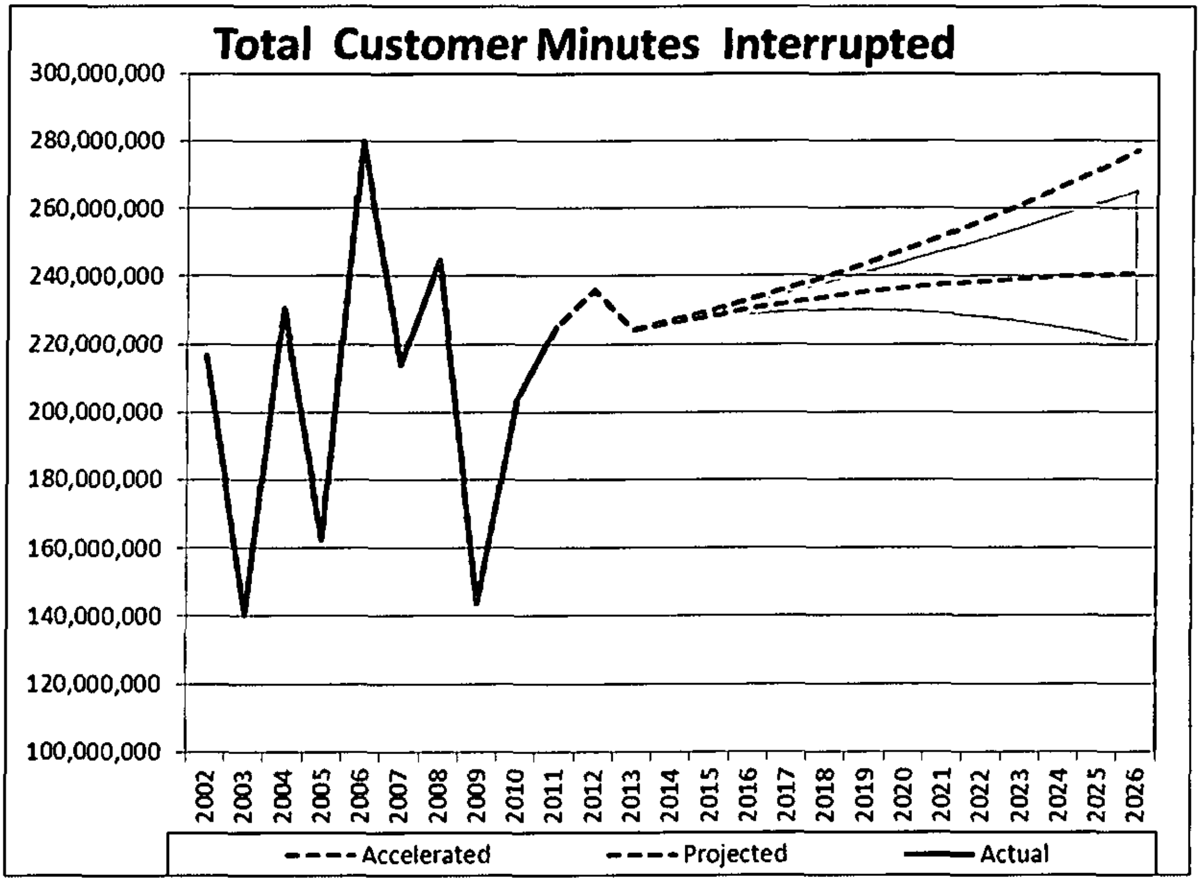
A.TUS-P-4. See TUS-P-4 Attachment 1, which shows the projected impact of accelerated investment on Customer Interruptions (CI) and Customer Minutes Interrupted (CMI).

CI and CMI are used as direct representations for SAIDI and SAIFI respectively. Projections are modeled beginning with a linear trend line based on historical performance. However, the primary outage driver (Equipment Failures) is not increasing linearly, but rather exponentially. That increase is reflected in the projection of future years.

The underlying data are highly volatile; therefore a range is modeled for the accelerated spending curve. The range reaches a maximum width of 1 standard deviation (½ SD up, ½ SD down) in 2026. Given the volatility of the data and difficulty inherent in projecting 14+ years, even this range may be overly conservative. Nevertheless, the data on TUS-P-4 Attachment 1 show that PPL Electric's accelerated investment in its infrastructure is *expected essentially to eliminate the projected increases in CI and CMI, and* potentially reduce those indices in the future.

PPL Electric Utilities Corporation





- Both charts exclude Major Events.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Petition of PPL Electric Utilities Corporation for Approval of its Long Term Infrastructure Improvement Plan	: : :	Docket No. P-2012-2325034

VERIFICATION

I, Stephen J. Gelatko, hereby state that the facts set forth in responses P-1 through P-4 are true and correct to the best of my knowledge, information and belief and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa. C.S. § 4904 (relating to unsworn falsification to authorities).

Date: October 29, 2012

Stephen J. Gelatko
Stephen J. Gelatko
Manager – Distribution Asset Management
PPL Electric Utilities Corporation

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CERTIFICATE OF SERVICE

I hereby certify that a true and correct copies of the foregoing **Responses to Data Requests** have been served upon the following persons, in the manner indicated, in accordance with the requirements of 52 Pa. Code § 1.54 (relating to service by a participant).

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Date: November 1, 2012

Jessica R. Rogers

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