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Final Report

Study of the Feasibility and Reliability of Undergrounding Electric Distribution Lines in the District of Columbia

Formal Case No. 1026

Submitted to

Public Service Commission of the District of Columbia

July 1, 2010

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July 1, 2010

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Public Service Commission of the District of Columbia
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Submission of Final Report
Study of the Feasibility and Reliability of Undergrounding Electric Distribution Lines in the District of Columbia
Formal Case No. 1026

Dear Mr. Ogbue,

Shaw Consultants International Inc. respectfully submits this final report in the matter above for review and acceptance by the Commission. This report is based on the information provided, at our request, by Pepco for the assets in the District of Columbia. This report completes our analysis of the feasibility and reliability of undergrounding electric distribution lines in the District and provides our recommendations and next steps.

Please contact me with any clarifications. It has been a pleasure working with you and your team on this effort.

Respectfully,

Philip DiDomenico
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Acronyms

Acronym	Full Name
CAIDI	Customer Average Interruption Duration Index
CIS	Customer Information System
CPI	Composite Performance Index
GIS	Geographic Information System
GPS	Global Positioning System
OH	Overhead
OMS	Outage Management System
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
UFA	Urban Forestry Administration
UFORE	Urban Forest Effects
UG	Underground
URD	Underground Residential Distribution
WMIS	Work Management Information System
WPF	Worst Performing Feeder

1 Executive Summary

The District of Columbia Public Service Commission (Commission) engaged Shaw Consultants International, Inc. (Shaw Consultants), formerly Stone & Webster Management Consultants, to conduct an independent study of the economic and technical feasibility and reliability implications of undergrounding electric distribution lines in the District of Columbia (District). The engagement began in March 2009. The Commission had previously ordered investigations by Potomac Electric Power Company (Pepco). This report provides the Commission with specific and unbiased feasibility and reliability information relative to undergrounding without recreating previously submitted studies.

The project's objectives included:

- Provide a comprehensive review and analysis of previous undergrounding studies including studies and analyses performed by Pepco
- Provide costs, feasibility, and reliability implications of select undergrounding alternatives to the existing overhead distribution system
- Examine the potential impacts of undergrounding projects on the environment, residents, infrastructure, and health and safety.

Shaw Consultants built upon the available record through our literature and web search, interviews with utility commission staff across the US, and review of Pepco's and others existing studies and costs to independently assess the methodology utilized by Pepco to assess the benefits and reliability improvements that may be derived from undergrounding. This report documents our approach, findings, and recommendations.

This document is organized as follows:

- *Introduction* – Provides an overview of the approach and methodologies used in this effort.
- *Review of Previous Studies and Industry Practice* – Summarizes the current literature relative to undergrounding and the results of interviews with other jurisdictions relative to undergrounding practices.
- *Pepco Reliability Programs and Statistics* –Reviews Pepco's historical reliability performance, analyzes implications of undergrounding on Pepco reliability, and summarizes Pepco's current reliability improvement programs as described to Shaw Consultants by Pepco.
- *Undergrounding Cost Review* – Reviews and updates Pepco's previous cost estimates and methodologies.
- *Assess Feasibility of Undergrounding* – Evaluates the benefits and costs of three Shaw Consultants defined undergrounding options.
- *Other Undergrounding Considerations* – Addresses the implications of environmental, residential, tourist, commercial and construction when implementing undergrounding.
- *Appendices* – Provides supporting information such as raw data from data requests to Pepco and meeting notes.

1.1 Summary of Recommendations and Observations

This investigation identified one jurisdiction that is currently undergrounding its existing overhead (OH) sub-transmission and primary distribution lines in Anaheim, California with the goal of improving aesthetics, reliability, and property values while reducing outages. Other jurisdictions are implementing targeted undergrounding efforts that address new development construction opportunities, reduce outages through storm hardening initiatives, and promote tourism.

In order to assess the reliability implications of undergrounding the Pepco system, Shaw Consultants investigated the reliability of existing overhead and underground (UG) circuits for a five year historical period, adjusted the statistics for storms and weather, and analyzed primary circuit reliability separately from secondary circuits. Our analysis indicates that should Pepco invest in undergrounding, the greatest improvement in reliability will be achieved by focusing on primary distribution circuits rather than secondary, since more customers are addressed at the primary level. The greatest value is achieved by undergrounding the primary distribution circuits because reliability increases more and at a lower cost than when compared to the investment necessary to underground secondary circuits, which impacts fewer customers and results in less improvement in reliability.

Based on available industry data, our review of Pepco-specific construction practices and standard industry construction costs, adjusted for District economic differences, indicates that Pepco's 2006 estimate of the cost to underground is reasonable, but would need to be inflated to represent construction costs today and for the future.

In Pepco's service territory undergrounding is currently considered when new residential developments are introduced. We do not recommend that the Commission introduce undergrounding for all existing circuits. Rather, the Commission should consider undergrounding in specific situations, such as a pairing of undergrounding with road expansion efforts in specific geographic sections of the District, or neighborhood projects in which the electric distribution undergrounding could be completed as part of a greater effort involving roadway reconstruction or large scale water and sewer replacement. By bundling infrastructure investment in this manner, sufficient benefits may accrue to justify the level of undergrounding investment.

1.1.1 Previous Undergrounding Studies

Conclusions reached through research into reviews of previous undergrounding studies, conducted in other states include the following:

- Reliability improvement data is limited, but the published data demonstrates that long term overall reliability may not improve
- The typical conclusion reached is that the reduction in the frequency of overhead outages is counter-balanced by increases in the duration of underground outages
- Methodologies focused on developing cost estimates of undergrounding existing overhead facilities with limited investigation valuing the benefits and estimating the cost-effectiveness
- Undergrounding costs per mile were found to range from $400,000 per circuit mile to $1.6 million per circuit mile, depending on the type of construction, topography and congestion, with many of the studies settling the average installation cost at $1 million per circuit mile as a broad estimate. These values are not adjusted for inflation or urban congestion costs, but are simply summaries of existing study conclusions.

- No study concluded that the quantifiable benefits provide justification for the increased costs of undergrounding existing overhead facilities. The 2006 Florida study did address additional qualitative benefits and determined that these types of benefits, which include health and safety and economic benefits, for example, reduced undergrounding costs by 50% over the long term – although the number of years was not specified in the report.
- Two studies, in Texas and Oklahoma, reached the conclusion that large scale undergrounding is not feasible but a targeted approach to undergrounding can be cost-effective. A targeted approach would combine aggressive vegetation management, hardening of key, outage-prone equipment, and limited undergrounding of key circuits. This is similar to Pepco's current practice.
- Overall, the studies conclude that large scale undergrounding is very expensive.
- These studies also identified several cost recovery approaches for investment in undergrounding existing facilities. These approaches include the conventional rate base approach, collecting a surcharge from all customers for a specified time frame to fund the increased investment, and requiring cost causing customers to contribute the incremental cost of undergrounding facilities.

1.1.2 Previous Pepco Studies

Key findings regarding the Pepco studies reviewed include:

- The 2004 study calculated an order of magnitude estimate of $4 billion for undergrounding the entire DC system.
- The 2006 study provided a more detailed estimate of undergrounding one feeder, and then extrapolated that estimate to fifteen feeders, for a cost of $1 billion, representing 13% of the then existing overhead system.
- The 2007 reliability study compared five of the worst performing overhead feeders to five underground feeders, and determined that reliability would be improved by moving those feeders underground.

1.1.3 Undergrounding in Other Jurisdictions

Shaw Consultants surveyed 50 state public service commission's to identify state undergrounding mandates and practices, and received responses from 40 states The survey revealed that in 25 states, the need to underground existing electric distribution lines has not been raised by customers to the regulators. There are five states that require UG for new subdivisions, and an additional six states in which certain municipalities are requiring UG. Florida, plus three other states are either implementing or investigating UG due to storm damage. Many respondents reported that undergrounding is raised by customers after a storm does significant damage, but that the issue is abandoned once the costs of undergrounding are demonstrated.

1.1.4 Pepco Reliability Review

Pepco estimated undergrounding reliability improvement based on a comparison of five of the fifteen worst performing overhead feeders to underground feeders with similar characteristics, such as number of customers and length of feeder. Shaw Consultants compared average feeders for both groups and also compared primary to secondary. The Shaw Consultants' study also provided a cost-benefit estimate of reliability improvements through undergrounding.

The following summarizes the conclusions from the reliability analysis of the ten average feeders:

- Significant outage incidents that involve large groups of customers and drive the SAIFI index higher are associated with both the OH and UG ***primary*** assets.
- Secondary incidents, while recognized as a great inconvenience for those customers involved, are insignificant in the total numbers of customers affected and also the typical feeder SAIFI. Of the 628 total outages, 64,198 customers were affected on the 10 typical feeders during the five-year period; of this total, 212 were secondary outages which affected only 495 customers (0.7%).
- The average annual incidents per circuit-mile of **combined** primary and secondary are 2.9 incidents per circuit-mile of overhead construction and 1.4 incidents per mile of underground construction for the ten typical feeders. The incidents per circuit-mile are based on *any event that took out any number of customers due to any cause for various durations and repair activities.*
- The CAIDI (duration) analysis for various events demonstrates that on average for non-storm events, the OH primary was repaired and restored in an average of 2.8 hours while UG repairs took on average 4.4 hours to complete. However, during storms the OH CAIDI increased to 8.2 hours while there were no UG storm related failures for comparison.
- Based on this review of existing data, secondary assets have a small effect on the total outage events and duration of the outages that the majority of customers experience. Any significant improvement in the performance of the District feeders will depend on making improvements in the overhead primary distribution system.

The reliability data developed using typical feeders serves as the basis for the following projections:

- Based on a five-year average, the total undergrounding of the present overhead primary, mainlines and laterals, would result in a decrease of 1.4 primary outage events per mile for the sections and areas where overhead primary is replaced by underground primary.
- For the 15 WPFs, undergrounding would result in a reduction of 0.7 incidents per circuit-mile to a level of 2.1 incidents per circuit-mile, which is the average underground primary incident rate.
- Similarly, CAIDI for non-storm incidents would increase approximately 1.6 hours based on historical data over an average 5 year period, with an average UG primary restoration time (CAIDI) in the range of 4.4 hours per event.

1.1.5 Pepco Cost Estimate Review

Shaw Consultants' review of the Pepco cost analysis concluded the following:

- Overall, the variations in estimated costs to underground existing overhead assets compare favorably with the original 2006 Pepco estimate of $3.5 million per mile. The difference in these cost estimates is not considered significant, given the scope of the project and the typical variations one would expect when comparing regional averages to specific local experience. The inclusion of the actual costs associated with the Anaheim project provides further substantiation to the reasonableness of both the Pepco and Shaw Consultants estimates.

1.1.6 Assessing Feasible Approaches to Undergrounding

The undergrounding feasibility analysis concluded the following:

- Undergrounding the mainline primary (Option 3) represents the most cost-effective solution if the number one concern is reliability, which is defined as reducing both the number of incidents and number of customers affected. However, if aesthetics are a major driver, undergrounding all overhead assets (Option 1) is the only approach that has the potential to eliminate all overhead construction and its associated visual impacts.
- Some benefits and costs associated with undergrounding remain difficult to quantify, at best. These include business impacts of construction, tourist implications of long-term construction in the nation's capital, inconvenience for residents and safety issues, to name a few. Section 7 of this report investigates these other benefits and costs. Adding these costs to the analysis would require significant additional research to put a value on the issues.
- One way to mitigate the costs but retain a significant portion of the reliability and aesthetic benefits is a targeted approach where all overhead assets are replaced on a limited basis based on selection criteria related to frequency and duration of outage events, customers willingness to pay, and other demographics. For example, Pepco or the Commission could identify "opportunities" for undergrounding such as when major or minor infrastructure improvements are taking place for other utilities, transportation systems, and road repair. Specific undergrounding related costs that might be candidates for cost sharing would include primarily excavation, conduit/manhole construction, and roadway paving costs.

A summary of the costs and projected benefits of three undergrounding strategies is provided in the table below. More detail and discussion relative to these estimates is included in Section 6 of this report.

Exhibit ES1 Undergrounding Strategies and Implications

Option*	Total Cost	Cost per Outage Avoided	Customers Affected (2008)	OH Customer Outages Avoided[1] (%)
Undergrounding All Mainline Primary (Option 3)	$ 1.1 Billion	$ 2.4 Million	73,384	65%
Undergrounding All Mainline Primary and Laterals (Option 2)	$ 2.3 Billion	$ 2.5 Million	97,650	87%
Undergrounding All Existing Overhead Assets (Option 1)	$ 5.8 Billion	$ 5.6 Million	112,345	100%

Option*	Reliability	Added Benefits
Undergrounding All Mainline Primary (Option 3)	462 fewer outage incidents, annually	Significant reliability improvement; least road-work needed to implement;
Undergrounding All Mainline Primary and Laterals (Option 2)	924 fewer outage incidents, annually	Additional reliability benefits, almost equal to those of Option 1; addresses 87% of customer outages caused by OH primary incidents
Undergrounding All Existing Overhead Assets (Option 1)	1030 fewer outage incidents, annually	Slightly increased reliability over Option 2; maximum aesthetic benefits

[1] While all overhead outages would be eliminated in option 1, they would be replaced to a lesser degree by underground outages

[2] There would be an increase in the number of manholes and therefore increases in related operational and maintenance issues.

* All options assume all overhead feeders in the Pepco system are placed underground.

1.2 Next Steps

Shaw Consultants recommends the Commission consider the following actions as part of any further investigation into the advisability of undergrounding:

- In order to assess the appropriate priority for undergrounding, the Commission should work with the extensive data in this report to develop decision criteria for future undergrounding opportunities so that there is no uncertainty for Pepco relative to cost recovery and support for a decision to invest.
- Targeted undergrounding opportunities should be explored in greater detail based on the decision criteria developed as per the previous bullet, which might include historical frequency and duration of outage events, customers' willingness to pay, and the availability of joint opportunities to cost share.
- The cost implications of retiring undepreciated, fully functioning overhead assets would have to be considered by the Commission for any undergrounding project (e.g., stranded cost of undepreciated amounts).

2 Introduction

On December 3, 2003, the Commission issued Order No. 12993, in Formal Case No. 1026, which opened an investigation to examine the feasibility of moving above ground utility lines and cables, and relocating them underground. On September 30, 2004, Pepco filed its initial report on the feasibility of undergrounding lines on a full-scale basis within the District of Columbia. In that report, Pepco presented its estimate of $4.1 billion in 2004 dollars for placing all of its remaining above ground lines and cables underground, but it did not recommend the wholesale undergrounding of its distribution system. The Company indicated that it remained receptive to working with its customers to explore selective modifications to improve overall electric service in a cost-effective manner.

On December 6, 2005, the Commission issued Order No. 13830 directing Pepco to "conduct a cost and feasibility study and submit a report regarding underground utility line conversion in selected areas within the District of Columbia historically known to be prone to power outages, and determine whether other sections of the District not necessarily susceptible to power outages – including individual residences, groups of residences, and commercial buildings – may be conducive to underground utility line placement." In addition, on February 10, 2006, the Commission issued Order No. 13877 in Formal Case No. 766 directing Pepco to "submit a cost and feasibility study regarding the potential undergrounding of feeders associated with Substation No. 133 as part of, and at the same time as, the cost and feasibility study to be submitted consistent with Order No. 13830, issued on December 6, 2005, in Formal Case No. 1026."

Pepco filed an undergrounding report with the Commission on June 5, 2006 in response to the Commission Orders issued in Formal Case Nos. 766 and 1026. Pepco's June 5, 2006 undergrounding report provided estimates for converting miles of existing overhead feeders and associated customer service drops to underground service. Pepco's $1.06 billion estimate was based on 15 feeders, 12 of which derived from Substation No. 133. According to Pepco, the estimated unit costs developed for undergrounding one feeder were applied to the other 14 feeders and their respective customer service connections included in the study.

On February 8, 2008, the Commission issued Order No. 14723, authorizing an independent study of the conversion of overhead utility lines to underground in the District of Columbia. The order also directed Pepco to submit additional information regarding any Pepco analyses conducted within the last three years evaluating whether specific feeders or groups of feeders should be placed underground. In addition, the Order directed Pepco to submit detailed guidelines for carrying out underground conversions and how the guidelines were developed and applied.

On April 8, 2008, Pepco submitted its response to Order No. 14273. The Company stated that it had not conducted any additional comprehensive analysis within the past three years that evaluated whether specific overhead feeders or groups of feeders in the District of Columbia should be placed entirely underground. Further, no detailed (general) guidelines for carrying out underground conversions exist because each reliability improvement project is individually engineered and designed to address specific issues and conditions. Finally, in its response, Pepco attached a copy of its procedure entitled, "AD-401, Relocation of Overhead Distribution Facilities to Underground Performed on Request" which addresses requests for undergrounding of distribution facilities.

Meanwhile, on March 14, 2008, the Commission issued RFP-08-03 to engage a technical consultant to conduct an independent study of the feasibility and reliability of undergrounding electric distribution lines in the District of Columbia and received responses to the RFP on April 14, 2008. After reviewing the RFP responses, the Commission restructured the RFP requirements. As a result, RFP No. PSC-08-03 was cancelled, and RFP No. PSC-08-09 was issued to conduct a condensed study of the cost, economic and technical feasibility, and the reliability of undergrounding electric distribution lines in the District of Columbia.

The study was not intended to replicate Pepco's and other previous studies, but rather to consider and enhance the record to the extent practical with an independent review and assessment of previous studies and current practices to support an informed decision on the economic and technical feasibility of undergrounding existing overhead lines in the District.

To address these requirements this report addresses the following areas:

- Economic and technical feasibility of converting Pepco's overhead electric distribution lines, cables, feeders and substation-related equipment to an underground system in parts of the District susceptible to frequent power outages, and evaluate whether undergrounding would be cost beneficial and lead to better, more reliable and less outage-prone electric service than currently exists in the entire system.
- Electric distribution undergrounding conversion rules, mandates, and best practices in other states' urban areas comparable to the District and by major electric utilities, including retrofit, selective and full undergrounding projects.
- Findings from other utility undergrounding studies across the United States.
- Findings from Pepco's and other previous studies.
- An estimate of the miles of existing above-ground feeders and associated customer service drops and an estimate of the time required for undergrounding those susceptible to frequent outages.
- Alternative methods used to develop the cost estimates and work scope descriptions.
- Environmental, community, and tree impact assessment related to undergrounding in outage-prone areas.
- Alternative approaches to undergrounding in conjunction with other public works related efforts in the District, including piggybacking with other undergrounding projects such as telephone, and joint –use cable conversions.
- Public safety, public health and occupational safety and health hazards and the overall risks associated with undergrounding projects.

The conversion of existing overhead electric distribution facilities to underground has been a hotly contested topic in the utility industry for many years. The topic has been studied, discussed, and debated many times at the state, municipal and local levels. The overwhelming conclusion is that the high cost of undergrounding existing overhead facilities cannot be justified based on reliability gains alone. The primary driver for undergrounding existing overhead lines has been aesthetic considerations, not reliability benefits. To date, almost all jurisdictions investigating undergrounding existing overhead systems have concluded that the cost of undergrounding all existing overhead facilities is prohibitive. Cost estimates for new underground construction are multiple times the cost of equivalent overhead construction.

Additional benefits beyond reliability that are often cited in undergrounding studies but difficult to quantify include:

- Improved aesthetics
- Lower tree trimming costs due to the reduced need for trimming
- Lower storm damage and associated restoration cost
- Fewer motor vehicle accidents from contact with poles
- Reduced accidental live-wire contact
- Fewer momentary interruptions
- Improved customer relations regarding tree trimming

However, there are also a number of potential disadvantages which need to be considered whenever the conversion of overhead facilities to underground is evaluated, these include:

- Environmental damage to existing curb trees in an urban environment
- Increased exposure to dig-ins
- Longer duration interruptions and more customers impacted per outage
- Susceptibility to flooding
- Underground cable has a shorter life expectancy than overhead wire, mainly due to water and animal intrusion, as well as insulation degradation

Despite the cost of undergrounding and questionable degree of benefits, many locals have developed comprehensive plans, on a system-wide or at least a partial basis, to bury or relocate utility lines, primarily to improve aesthetics. Targeted undergrounding has also been adopted as a means of obtaining the greatest reliability value at a cost substantially below what would be required for a system-wide undergrounding effort.

This report will explore many of these issues with the intent to provide the Commission with up-to-date data and information on costing, economic and technical feasibility mandates and practices for the undergrounding of the electric distribution system in the District of Columbia, and the reliability improvement to be expected from undergrounding in areas prone to outages.

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3 Review of Previous Studies and Industry Practice

One key objective of our investigation is to provide a description of how utilities, regulators, stakeholders, and communities across the country have evaluated and addressed the issue of moving pre-existing overhead distribution facilities to underground systems ("undergrounding"), especially in urban environments similar to the District of Columbia. A critical element of this effort is the identification, collection, review, and independent assessment of previous studies and practices, to support a well-informed and rigorous analysis for application to the Pepco system. Our investigation gathered information relative to study methodologies, estimated costs of undergrounding, topics considered in the studies, and issues addressed or identified for further analysis in undergrounding studies already completed. We also completed primary research by contacting regulators in every US state to compile a summary of current industry practices with respect to undergrounding. This chapter of the report summarizes our findings. Shaw Consultants International conducted this assessment in the second quarter of 2009 through online research, investigation of published literature, and interviews of knowledgeable utility and regulatory personnel.

More specifically, Shaw Consultants' assessment included the following elements:

- Review of previous undergrounding studies conducted in other states;
- Review and analysis of Formal Case 1026 studies and filings submitted by Pepco to the District of Columbia Public Service Commission; and
- Interviews with Public Utility Commission and utility staff from other jurisdictions regarding current or anticipated undergrounding programs, state mandates and key issues.

3.1 Examples of Current Undergrounding Projects

Florida has experienced an increase in hurricane events in recent years, generating strong interest in undergrounding as an alternative, with several of the recent studies focused on this state. Many municipalities in Florida are moving ahead with focused undergrounding projects that were approved to address both aesthetics and perceived storm reliability benefits. A tariff has been established that allows customers to pay the incremental cost of undergrounding.

The barrier island region of southeastern North Carolina, served by the Brunswick Electric Membership Corporation, a cooperative utility, has undergone an extensive conversion of its distribution system, after having a program in place since the early 1990s, and has reported much improved storm related restoration and reliability.

Ocean City, Maryland has had success with its undergrounding program, in which the municipality is managing the whole process, funded by general obligation bonds.

Puget Sound Energy, covering 6,000 square miles and 11 counties in western Washington State, has approximately 50% of its existing distribution lines underground, and places all new lines underground. There is a tariff in place requiring customers to pay a share of undergrounding existing wires.

Anaheim, California is in the midst of a fifty-year underground conversion program, begun in 1990, in an attempt to underground all distribution lines along all major arterial roadways. While the main goal is improved aesthetics, reduced tree trimming costs and increased reliability are seen as potential benefits. As of 2008, 97 circuit miles have been placed underground and $125 million has been spent.

Discussions about undergrounding power lines are commencing in Kentucky, after recent storms caused severe damage.

Missouri's Project Power On, a $300 million effort on the part of AmerenUE, is a targeted approach to storm related restoration and reliability improvement.

3.2 Reviews of Previous Undergrounding Studies Conducted in Other States

Shaw Consultants' review of previous undergrounding studies included 17 reports and projects from 8 states and Australia, dating from 1998 to 2009. Based upon this review, we identified four main issues addressed by these studies including the cost of undergrounding, the benefits of undergrounding, an assessment of the UG reliability impacts, and identification of potential sources of funding. Many of the studies referenced previous undergrounding studies and relevant literature, and therefore built upon each other; as a result, each reaches similar conclusions with regard to consideration of these issues.

Highlights of the research's conclusions include:

- Reliability improvement data is limited, but the published data demonstrates that long term overall reliability may not improve
- The typical conclusion reached in these studies is that the reduction in the frequency of overhead outages is counter-balanced by increases in the duration of underground outages
- Methodologies focused on developing cost estimates of undergrounding existing overhead facilities with limited investigation valuing the benefits and estimating the cost-effectiveness
- Undergrounding costs per mile were found to range from $400,000 per circuit mile to $1.6 million per circuit mile, depending on the type of construction, topography, and congestion, with many of the studies settling the average installation cost at $1 million per circuit mile as a broad estimate. These values are not adjusted for inflation or urban congestion costs, but are simply summaries of existing study conclusions.
- No study concluded that the quantifiable benefits provide justification for the increased costs of undergrounding existing overhead facilities. The 2006 Florida study did address additional qualitative benefits and determined that these types of benefits, which include health and safety and economic benefits, for example, reduced undergrounding costs by 50% over the long term – although the number of years was not specified in the report.
- Two studies, in Texas and Oklahoma, reached the conclusion that large scale undergrounding is not feasible but a targeted approach to undergrounding can be cost-effective. A targeted approach would combine aggressive vegetation management, hardening of key, outage-prone equipment, and limited undergrounding of key circuits.
- Overall, the studies conclude that large scale undergrounding is very expensive.
- These studies also identified several cost recovery approaches for investment in undergrounding existing facilities. These include the conventional rate base approach, collecting a surcharge from all customers for a specified time frame to fund the increased investment, and requiring customers to contribute the incremental cost of undergrounding facilities.

Of particular interest is the undergrounding activity in the city of Anaheim. The city of Anaheim, California is 19 years into a 50-year undergrounding project that includes moving existing sub-transmission and primary distribution lines underground along major transportation corridors. Anaheim's goals are to improve local aesthetics, reduce outages, reduce their tree trimming costs, and increase local property values. This initiative is being funded by a surcharge on customer bills.

Exhibit 1 summarizes the studies reviewed as part of this effort. More detailed summaries of each are provided in tabular form in Section 3.2.1 of this report.

Exhibit 1 Undergrounding Studies Reviewed

Year	State	Report Title	Estimated Cost per Circuit Mile	Study Driver	Study Methodology
Cur.	MO	Project Power On	N/A	UG program	Targeted UG with initial $300 million investment budget; investment is prioritized to complete lowest cost projects first
2009	TX	Cost-Benefit Analysis of the Deployment of Utility Infrastructure Upgrades and Strom Hardening Programs	N/A	Costs & Benefits of Storm Hardening	Reviewed utility cost data, hurricane simulation model
2008	OK	Inquiry into Undergrounding Electric Facilities	$1.5 million for mainline, $0.5 million for lateral	Cost & Reliability	Reviewed previous studies, interviewed utility and government staff, collected utility data
2008	FL	Infrasource Study Phase 3: Modeling	N/A	Model future costs & benefits	Developed model for calculating costs
2007	FL	Infrasource Study Phase 2: Case Studies	$400,000 to $1.6 million	Costs & benefits of completed projects	Review of actual costs and benefits for four UG projects
2007	FL	Infrasource Study Phase 1: Literature Review	N/A	Cost	Review of previous studies
2006	FL	Cost-Effectiveness of Undergrounding Electric Distribution Facilities in Florida	$1.1 million	Cost - effectiveness	Includes qualitative benefits in study
2006	N/A	Out of Sight, Out of Mind (Multi-state study, commissioned by EEI)	$1 million	Costs, benefits, reliability	Review of Previous Studies

Year	State	Report Title	Estimated Cost per Circuit Mile	Study Driver	Study Methodology
2005	NY	Review of Undergrounding Policies and Practices	N/A	Nationwide Policies	Review of Previous studies and LIPA system
2005	FL	Preliminary Analysis of Placing Investor-Owned Electric Utility Transmission and Distribution Facilities	N/A	Cost	Updated undergrounding costs based on a cost estimate from 1991
2005	VA	Virginia Corporation Commission	N/A	Feasibility, Costs, Funding	Developed costs and benefits
2004	MD	Hurricane Isabel Response Assessment	N/A	Reliability	Investigation of storm preparedness and restoration
2003	MD	Maryland Task Force to Study Moving Overhead Utility Lines Underground	N/A	Cost	Evaluated costs and funding alternatives
2003	NC	Statewide Undergrounding Study	N/A	Cost	Developed estimate of undergrounding entire state
2002	NC	A Five-year Survey of Underground and Overhead Reliability Comparisons for North Carolina (1998-2002)	N/A	Reliability	Investigated frequency and duration of outages for both OH and UG
2000	MD	Maryland PSC	$1 million	Reliability	Compared reliability of OH feeders with UG feeders
1998	Aust.	Putting Cables Underground Working Group (Australia)	N/A	Feasibility, Costs, Regulatory Issues	Public finance principles, benefits, assessment of funding options, avoided cost model

3.2.1 Summaries of Published Undergrounding Studies

This section provides descriptions of each of the studies reviewed by summarizing the methodologies utilized and the general conclusions reached in each case. The studies have been provided electronically to the DC PSC for reference. For certain of the studies identified here, the Shaw Consultants team contacted individual utilities to assemble more specific information about the studies including approach, cost development, and tactical implementation plans.

Project Power On (MO) - Ongoing

AmerenUE was profiled in the January 2009 issue of T&D World magazine with regard to its $300 million Power On effort that was initiated in July 2007, after several severe storms caused widespread outages of long duration. Project Power On is being used to target investment in the system to reduce storm related outages. The Shaw Consultants team interviewed the project manager who indicated that the effort was focused on storm-driven reliability improvement, to reduce most restoration issues after storms. A summary of the points raised during our interview found:

- Before this project, AmerenUE had reliability within the 2nd quartile nationwide.
- A "backyard distribution system" (primary, poles and secondary) built in the 1950's is creating problems today due to the fact that it is difficult to access those assets with a bucket truck.
- Fifty year old trees in those backyards are now 80-90 feet tall and are sources of large limbs prone to fall in storms.
- Storm related outages occur several weeks after storms due to weakened limbs and trees that continue to fall.
- Early results of this program indicate that customers are appreciative of the attempt to improve reliability, although some customers did not want a transformer on their front lawn, and have declined the UG service. Some neighborhoods are working together, obtaining group pricing on the switch to UG service.

In order to evaluate the underground system, AmerenUE developed a cost per circuit mile for the preliminary screening against outage events. As potential projects are identified, a project sheet is developed with the estimated costs developed for each application.

Exhibit 2 Project Power On Summary

Project Power On *Missouri*	
Study Description	AmerenUE initiated its $300 million Project Power On in July 2007, after several severe storms caused widespread outages with long durations.
Date of Study	Ongoing
Focus	Undergrounding program to address storm hardening
Methodology	AmerenUE is using "Cost per Annual Avoided Customer Interruption" to determine which undergrounding projects offer the greatest potential. Areas of high frequency (SAIFI) are looked at for possible improvement, and the resulting improvement or change in expected outage frequency is developed based on the outage-causing assets being eliminated. This information and analysis is then used to establish the cost per incident. Projects are prioritized based on lowest cost projects (per avoided interruption).
Conclusions	The early results from this undergrounding initiative appear to be positive. Customers are appreciative of undergrounding efforts but generally do not want a transformer box on their front lawn. While AmerenUE has offered customers partial payment for moving their service underground and connecting to a new pedestal in the backyard, most customers have chosen not to underground their service line. Other utilities sharing the existing poles have not expressed interest in undergrounding, so poles are being topped off and remain in place for other utilities.
Cost Estimates	AmerenUE will request that the cost of program be added to their rate base after completion of the project. After the initial $300 million is spent, AmerenUE will review results and then decide whether and how to proceed.

Cost-Benefit Analysis of the Deployment of Utility Infrastructure Upgrade and Storm Hardening Programs (TX) 2009

Texas hurricanes during the past decade have caused a significant amount of utility infrastructure damage and other societal cost. Broad prescriptive approaches to hurricane hardening are generally expensive and not adopted since many structures must be hardened for every potential failure. However, certain targeted vegetation and hardening approaches can be cost-effective, especially if they are based on detailed post-storm data collection and analyses.

This report examined the costs, utility benefits, and societal benefits for a variety of storm hardening programs. The study collected cost data from Texas utilities and a hurricane simulation model. The study determined that targeted hardening of transmission structures is generally not cost-effective. However, the transmission structures of Entergy Texas experienced extremely high failure rates during Hurricanes Rita and Ike. Based on these high failure rates, follow-up analysis showed that the targeted hardening of Entergy Texas transmission structures is potentially cost-effective and should be investigated further.

The three cost-effective storm hardening strategies determined by this study:

- *Improved post-storm data collection.* Most damage data available to utilities comes from accounting and work management systems, but a much better understanding of infrastructure performance can result from carefully designed post-storm data collection programs that capture key features at failure sites. Improved capture of storm data allows for more cost-effective spending on hardening programs.
- *Tree removal.* Removing dead and diseased trees that are outside the right of way, but have the potential to fall onto utility equipment, are considered desirable from a societal perspective and can significantly reduce hurricane damage. Additional benefits are possible with the removal of healthy trees that could fall and damage equipment.
- *Targeted electric distribution hardening.* By targeting spending on high priority circuits and important structures, costs can be minimized. The hardening of about 1% of distribution structures has the potential to be cost-effective for Texas utilities.

Exhibit 3 Cost-Benefit Analysis of the Deployment of Utility Infrastructure Upgrades and Storm Hardening Programs Summary

Cost-Benefit Analysis of the Deployment of Utility Infrastructure Upgrades and Strom Hardening Programs *Texas*	
Study Description	Examined the costs, utility benefits, and societal benefits for a variety of storm hardening programs.
Date of Study	2009
Focus	Costs & Benefits of Storm Hardening
Methodology	This study collected hurricane damage and cost data from Texas utilities and utilized a hurricane simulation model. The utility data was used to develop a probabilistic model, which formed the basis for the cost-to-benefit analyses. The hurricane simulation model that was used simulates hurricane years. For each year, the model determines the number of hurricanes that make Texas landfall, as well as the size, strength, landfall location, path, infrastructure damage, and restoration time for each hurricane. The average results of simulation years are used for cost and benefit calculations.
Conclusions	The study determined that targeted hardening of transmission structures is generally not cost-effective. The three cost-effective storm hardening strategies determined by this study; ▪ Improved post-storm data collection, ▪ Diseased tree removal, and ▪ Targeted electric distribution hardening.
Cost Estimates	Since 1998, electric utilities in Texas have incurred approximately $1.8 billion in restoration costs due to hurricanes and tropical storms, for an average of about $180 million per year. About 80% of these costs are attributed to distribution and 20% to transmission. Nearly all of the restoration costs are attributed to wind damage, tree damage, and flying debris. Storm surge damage is occasionally a major concern in specific areas, but generally represented a low percentage of restoration costs.

Inquiry into Undergrounding Electric Facilities (OK) 2008

The Oklahoma Corporation Commission, in an exhaustive study, investigated undergrounding by reviewing past studies, collecting utility data, interviewing utilities and government agencies, and developing cost estimates. The Commission concluded that undergrounding all electric facilities is not feasible, based on their cost estimates. Their analysis led them to recommend a targeted undergrounding approach, supplemented with targeted hardening of overhead facilities, in order to avoid the cost associated with undergrounding the whole system.

Exhibit 4 Inquiry into Undergrounding Electric Facilities Summary

Inquiry into Undergrounding Electric Facilities *Oklahoma*	
Study Description	Investigated undergrounding by reviewing past studies, collecting utility data, interviewing utilities and government agencies, and developing cost estimates.
Date of Study	2008
Focus	Cost & Reliability
Methodology	Reviewed previous studies, interviewed utility and government staff, and collected utility data.
Conclusions	The Commission concluded that undergrounding all electric facilities is not feasible, based on their cost estimates. Their analysis led them to recommend a targeted undergrounding approach, supplemented with targeted hardening of overhead facilities, in order to avoid the enormous cost associated with undergrounding the whole system. Report recommendations: ▪ Require more aggressive vegetation management; ▪ Bury all new lateral distribution lines except where low population density makes it impractical; ▪ Bury existing lateral distribution when requested by a majority of customers in a neighborhood; ▪ Identify fully urbanized main distribution lines and require burial when wire is replaced; ▪ Require utilities to underground distribution lines when relocating for major road and highway projects; ▪ Harden all highway-crossing electric lines identified as causing disruptions during storms because of falling onto the roadway; ▪ Require utilities to erect self-standing poles in strategic locations for transmission lines and targeted distribution lines; ▪ Harden worst-performing circuits; ▪ Bury drop lines and/or create a pilot program to test newly available “service entrance disconnect systems”; and ▪ Create incentives for “smart-grid” installations allowing for rerouting of electric power around downed lines, transformers, and other equipment.
Cost Estimates	Cost per mile to underground lateral distribution lines: $500,000 Cost per mile to underground main distribution lines: $1,500,000

Infrasource Study (FL) 2007 – 2008

The Florida undergrounding study completed by Infrasource involved three phases: a literature review, a series of case studies, and the use of a hurricane model to assess the benefits of undergrounding.

Phase 1: Literature Review

This study was a comprehensive literature review and assessment of previous undergrounding studies, in Florida and nationwide. The review revealed that the conversion of overhead electric distribution systems to underground is costly and far in excess of any quantifiable benefits.

Exhibit 5 Infrasource Study, Phase 1 Summary

Infrasource Study Phase 1: Literature Review *Florida*	
Study Description	A comprehensive literature review and assessment of previous undergrounding studies, in Florida and nationwide.
Date of Study	2007
Focus	Cost
Methodology	Review of previous studies
Conclusions	The review revealed that the conversion of overhead electric distribution systems to underground is costly, and that these costs are far in excess of any quantifiable benefits. It was determined that no state is currently requiring undergrounding of existing distribution facilities.
Cost Estimates	The review revealed that the conversion of overhead electric distribution systems to underground is costly, and that these costs are far in excess of any quantifiable benefits. It was determined that no state is currently requiring undergrounding of existing distribution facilities.

Phase 2: Case Studies

Phase 2 of the study evaluated four completed underground conversion projects in Florida. The study collected the actual costs in an attempt to approximate the "turnkey" cost that a utility would need to pay an external contractor for a similar project. The cost per mile for undergrounding existing lines in these projects ranged from approximately $400,000 to $1.6 million per mile, depending on the construction type and local conditions. This review of case studies resulted in the same conclusion reached in Phase 1, that the costs of undergrounding outweighed the quantifiable benefits. The cost per circuit mile of undergrounding corresponded to those identified in the Phase 1 literature review. Non-storm reliability was not significantly different for underground service. Due to damage from hurricane storm surge, reliability was reduced for underground installations.

Phase 3: Modeling

Phase 3 of the study developed a hurricane simulation model capable of predicting the costs and benefits to all stakeholders for potential underground conversion projects then compared these costs and benefits to a hardened overhead system.

Cost Effectiveness of Undergrounding Electric Distribution Facilities (FL) 2006

This study addressed the total cost and benefit, not only of the installation costs of underground versus overhead wires, but also of the differences in operating and maintenance costs. This study was different from other studies in that an attempt was made to calculate both quantitative and qualitative benefits. Qualitative benefits include health and safety (during and after a storm), aesthetics, reliability, reduced economic disruptions, environmental benefits, and general community enhancement.

Exhibit 6 Cost Effectiveness of Undergrounding Electric Distribution Facilities Summary

Cost Effectiveness of Undergrounding Electric Distribution Facilities *Florida*	
Study Description	This study addressed the total costs and benefits of undergrounding existing lines.
Date of Study	2006
Focus	Cost-effectiveness
Methodology	The researchers submitted an extensive data request to Florida Power & Light and completed site visits to 5 municipalities with varied underground conversion issues. A site visit was also made to a cooperative utility in North Carolina which serves a barrier island with topography similar to coastal Florida and had completed an extensive undergrounding conversion of its entire system. A detailed cost estimate was developed for each type of construction (e.g., single phase, three phase) for hurricane-hardened overhead lines and for underground lines on a per circuit-mile basis. This study was different from other studies in that an attempt was made to calculate both quantitative and qualitative benefits. Qualitative benefits included health and safety (during and after a storm), aesthetics, reliability, reduced economic disruptions, environmental benefits, and general community enhancement.
Conclusions	The study concluded that the cost of undergrounding will be somewhat mitigated as benefits related to maintenance and repair costs of overhead lines are avoided- possibly reducing the costs by 50% when all benefits, including qualitative benefits, are accounted for. Seventy percent of all new distribution in Florida is being placed underground.
Cost Estimates	Undergrounding existing overhead facilities costs $1.1 million per mile.

Out of Sight, Out of Mind (Multiple States) 2006

This report by the Edison Electric Institute provides a summary overview of previously completed studies in the U.S. It examined historical performance data for underground and overhead lines to evaluate the costs and benefits of placing existing overhead electric distribution infrastructure underground. The report concluded that underground power systems tend to have fewer power outages, but the duration of these outages tend to be much longer. Underground power systems also are not immune from outages during storms.

Exhibit 7 Out of Sight, Out of Mind Summary

Out of Sight, Out of Mind - Edison Electric Institute *Multiple States*	
Study Description	This report by the Edison Electric Institute (EEI) provides a summary of previously completed studies in the U.S. covering numerous states.
Date of Study	2006
Focus	Costs, Benefits, Reliability
Methodology	The study provides an overview of previously completed undergrounding studies, and examined historical performance data for underground and overhead lines to assess the costs and benefits of placing existing overhead electric distribution infrastructure underground.
Conclusions	The report concluded that underground power systems tend to have fewer power outages, but the duration of these outages tends to be much longer than overhead systems. It also concluded that underground power systems are not immune from outages during storms. Reliability benefits associated with burying existing overhead power lines are uncertain and, in most instances, do not appear to be to be sufficient to justify the high price tag that undergrounding carries.
Cost Estimates	Undergrounding costs were estimated at approximately $1 million per mile. • The cost differential for underground lines was estimated at ten times the cost of overhead lines.

Review of Undergrounding Policies and Practices (NY) 2005

A review of LIPA undergrounding costs and nationwide studies reached the conclusion that the perceived advantages of underground lines are overstated. For example, the aesthetic improvement of underground lines comes at enormous extra cost compared to overhead construction, possibly triggering large rate increases over time. The study concluded that, within industry experience, underground lines do not improve overall system reliability, generally substituting longer outages in exchange for less frequent interruptions compared with overhead lines.

Exhibit 8 Review of Undergrounding Policies and Practices Summary

Review of Undergrounding Policies and Practices *Long Island Power Authority*	
Study Description	This report provides a summary of previously completed studies in the U.S. and a review of the potential costs of LIPA specific undergrounding activities.
Date of Study	2005
Focus	Nationwide policies
Methodology	Review of Previous studies and the LIPA system
Conclusions	▪ The majority of LIPA's distribution system, approximately 68%, was comprised of overhead lines. ▪ Over 90% of the annual number of customer interruptions on the LIPA distribution system occurred on distribution primary and secondary overhead construction. ▪ Interruptions on LIPA's transmission system accounted for less than 2% of the annual number of customer interruptions.
Cost Estimates	Cost estimates for underground construction are estimated at ten times the cost of overhead construction varying from $500,000 to several million dollars a circuit-mile.

Preliminary Analysis of Placing Investor-Owned Electric Utility Transmission and Distribution Facilities (FL) 2005

This study developed a ballpark estimate of the cost for investor-owned electric utilities to underground existing electric transmission and distribution facilities in Florida. The conversion cost estimate was primarily based on cost estimates from the Florida 1991 Commission study, adjusted for inflation. The study concluded that it would require approximately $51.8 billion of investment to underground the existing <u>transmission</u> lines of the five electric investor-owned utilities in Florida. Assuming conversion and cost recovery over a ten-year period, the impact for such an undertaking, on a per kWh basis for all customers combined for these utilities, would be an increase in rates of approximately 49.7% for the ten year period.

The estimated cost to place existing <u>overhead distribution lines and feeders</u> underground for the five investor-owned electric utilities was $94.5 billion. This estimate included (1) the cost of converting existing overhead facilities within subdivisions to underground and (2) the cost of converting the feeders connecting the subdivisions and commercial districts to the generation and transmission supply system. Assuming conversion and cost recovery over a ten-year period, and assuming that the $94.5 billion estimated cost of undergrounding distribution feeders and subdivisions was spread over all rate payers for the combined IOUs, the impact on the average cost per kWh, would be an increase of 81.1% in the first year, with the increased rates continuing for the ten year period. These estimated costs only included utility costs for conversion of existing facilities; no external or customer costs were considered.

An inflation rate of 2.44% per year over the ten-year period was assumed. Also, it was assumed that O&M savings will be approximately 0.7% of the gross investment in underground facilities each year. This savings percentage was based on comparing the respective costs for overhead and underground O&M expenses as reported in the 2003 FERC Form 1 for distribution facilities. Distribution data was used since O&M expense data for underground transmission facilities was not separately identified in the FERC Form 1. The percent rate impact is with respect to all customer electric utility costs, including base rates and fuel.

Virginia Corporation Commission (VA) 2005

This was a statewide cost and benefit study of undergrounding from which the Virginia commission calculated that the benefits would offset only about 38 percent of total costs and concluded that a comprehensive statewide effort to bury the state's electric distribution system appeared "unreasonable."

Exhibit 9 Virginia Corporation Commission Summary

Virginia Corporation Commission *Virginia*	
Study Description	A statewide feasibility study of undergrounding all existing overhead electric utility distribution facilities.
Date of Study	2005
Focus	Feasibility, Cost, Funding
Methodology	The commission reviewed previous undergrounding reports, collected and analyzed utility cost data, and surveyed customers regarding their willingness to pay for conversion of overhead facilities to underground. Commission staff also completed a case study of the actual costs of a completed undergrounding project in the City of Norfolk.
Conclusions	The Virginia commission calculated that the benefits would offset only about 38 percent of total costs and concluded that a comprehensive statewide effort to bury the state's electric distribution system appeared unreasonable.
Cost Estimates	The cost to place all existing overhead electric utility distribution facilities underground was estimated to be over $80 billion, or approximately $3,000 per customer. The additional cost to place all telecommunications and cable television lines underground was approximately $11 billion.

Hurricane Isabel Response Assessment (MD) 2004

This assessment was an extensive review of Pepco's preparation for and response to Hurricane Isabel and reviewed Pepco's storm response in the areas of planning, response, and customer service, with a short discussion of the role that undergrounding can play in storm reliability. The report highlighted an Ocean City, MD, undergrounding program as a best practice, where the local municipality managed the underground conversion project, which was financed by the city using general obligation bonds. No specific cost estimates were developed.

Maryland Task Force to Study Moving Overhead Utility Lines Underground (MD) 2003

This study identified how to reduce the costs of transferring overhead utility lines underground.

Exhibit 10 Maryland Task Force to Study Moving Overhead Utility Lines Underground Summary

Maryland Task Force to Study Moving Overhead Utility Lines Underground *Maryland*	
Study Description	Identified approaches to reduce the costs of transferring overhead utility lines underground.
Date of Study	2003
Focus	Cost
Methodology	The task force investigated previous reports on undergrounding; those focused in Maryland and nationwide, assessed, state and local regulatory impacts on undergrounding, and identified implemented projects and funding approaches.
Conclusions	The study concluded that, in most cases, improved aesthetics are the primary reason to underground overhead utilities, but undergrounding remains very expensive. Other findings: ▪ Economies of scale can be realized if all utilities are undergrounded at the same time. ▪ Further savings can be realized if undergrounding is done in conjunction with other infrastructure projects. ▪ Frequency of outages can be significantly improved in the short term, but the long term reliability of undergrounding is more questionable. ▪ Underground outages may occur less frequently, but generally take longer to repair.
Cost Estimates	$450,000 per mile

Statewide Undergrounding Study (NC) 2003

This extensive cost study, initiated after severe storms, determined that replacing the existing overhead distribution lines of the (state's investor-owned) utilities with underground lines would be prohibitively expensive. Such an undertaking would cost approximately $41 billion, nearly six times the net book value of the utilities' current distribution assets, and would require approximately 25 years to complete. The ultimate impact of the capital costs alone on an average residential customer's monthly electric bill would be an increase of 128.7%.

The Commission staff estimated that the $41 billion investment would increase the Utilities' combined annual revenue requirement by $8.8 billion and have a rate impact of approximately 10 cents per kWh. With average rates of 7.77 cents per kWh for residential service, 6.15 cents per kWh for commercial service, and 4.63 cents per kWh for industrial service, an additional 10 cents per kWh would increase residential rates by 128.7%, commercial rates by 162.6%, and industrial rates by 216%. The average bill of a residential customer using 1,000 kWh per month would increase from $77.70 to $177.70 per month.

Repair time was determined to be 60% longer for underground installations, while maintenance costs were four times that of overhead equipment. Consequently, the Task Force did not recommend that the utilities undertake the wholesale conversion of their overhead distribution systems to underground.

Exhibit 11 Statewide Undergrounding Study Summary

Statewide Undergrounding Study *North Carolina*	
Study Description	An extensive cost study, initiated after severe storms, to develop estimate of undergrounding entire state
Date of Study	2003
Focus	Cost
Methodology	Consisted of (1) comparing the operational advantages and disadvantages of overhead and underground power distribution systems; (2) estimating and comparing the capital costs of converting overhead lines to underground, along with the differences in operation and maintenance (O&M) costs for the two types of systems; (3) estimating the time and human resources required to bury underground lines; (4) identifying potential additional costs to customers, municipalities, and other utilities that may result from conversion; and (5) exploring options for financing conversion projects.
Conclusions	Determined that replacing the existing overhead distribution lines of the (state's investor-owned) utilities with underground lines would be prohibitively expensive.
Cost Estimates	$41 Billion statewide.

A Five-year Survey (1998-2002) of Underground and Overhead Reliability Comparisons (NC) 2002

This survey determined that the frequency of outages with underground systems was 50 percent less than for overhead systems, but that the average duration of an underground outage was 58 percent greater than for an overhead outage.

Maryland PSC (MD) 2000:

One of the few studies to address the reliability of undergrounding, this study compared overhead and underground feeders to determine a reliability benefit. The study investigated the reliability of "comparable" overhead and underground feeders and concluded that the impact of undergrounding existing lines was, at best, unclear. Study conclusions included:

- As underground cables approach their end of life, failures increase significantly and are extremely difficult to locate and repair.
- Maryland utilities say their underground cables become unreliable after 15 to 20 years and reach their end of life after 25 to 35 years.
- The average cost per mile of undergrounding was estimated at $1 million.
- The useful life of underground cables is shorter than for overhead, and the duration of outages for underground is 2 or 3 times as long as overhead.

International Undergrounding Study (Australia) 1997 – 1998

A working group was established to investigate the potential for undergrounding the Australian distribution system. This study resulted in three reports and a model for calculating costs.

Exhibit 12 Putting Cables Underground (PCU) Working Group Summary

Putting Cables Underground (PCU) Working Group *Australia*	
Study Description	An examination of undergrounding distribution systems in Australia, which consist of a set of reports which collectively form a comprehensive study for a state sponsored working group (PCU Working Group)
Date of Study	1997-1998
Focus	Technical, Economic and Regulatory Issues
Methodology	Public finance principles related to underground funding options – The first report in the series focused on two case studies with detailed information on the cost to provide underground service to residential lots. Various options considered including charging based on property value, property frontage, or a level fixed cost irrespective of property value or frontage. Benefits – The second report focused on the benefits of undergrounding, reviewing available literature and interviewing representative stakeholders. In assessing each identified benefit, the likely magnitude and significance was considered, and whether enough data would be available to estimate the value of the benefit. Assessment of funding options – The third report provides principles to assist in determining whether an undergrounding project should proceed, who the decision maker should be, and comparing various funding options. Developed an Avoided Cost Model – A model for calculating avoided costs, which provide the basis for stakeholder contributions to cost in various underground funding options, was developed using data supplied by Australian utilities related to preventive and reactive maintenance activities.
Conclusions	▪ Average cost to convert residential lots was calculated to be US$5,500 in 1997 dollars, with the actual cost per lot ranging from $1,000 to $38,000. A survey conducted in the case study areas received a 40% response rate from customers, and revealed that 80-85% of respondents were in favor on the conversion and 70% were willing to contribute at least part of the cost of undergrounding their lots. The conversion to underground was being justified based on visual impact, reliability impact, and maintenance savings, but no funding option was singled out as a recommendation by the study. ▪ The main benefits of undergrounding are urban amenity benefits, including improved visual amenity, improved streetscape aesthetics, and reduced pruning of trees, but valuation of these intangible benefits is unachievable. Whether these intangible benefits, when combined with actual quantifiable benefits, outweigh the cost of undergrounding, needs to be determined by locality and by project. ▪ The benefits of undergrounding are highly subjective and not easy to quantify. For each specified benefit, the report determined whether a methodology and data exist to quantify it, assessed the relative measurement difficulty, and assessed the benefit's significance. The report contained no specific cost data. ▪ The principles are presented not as a definitive answer but to provide an analytical framework to assist decision making with regard to funding options. The report quantified at a high level the benefits of

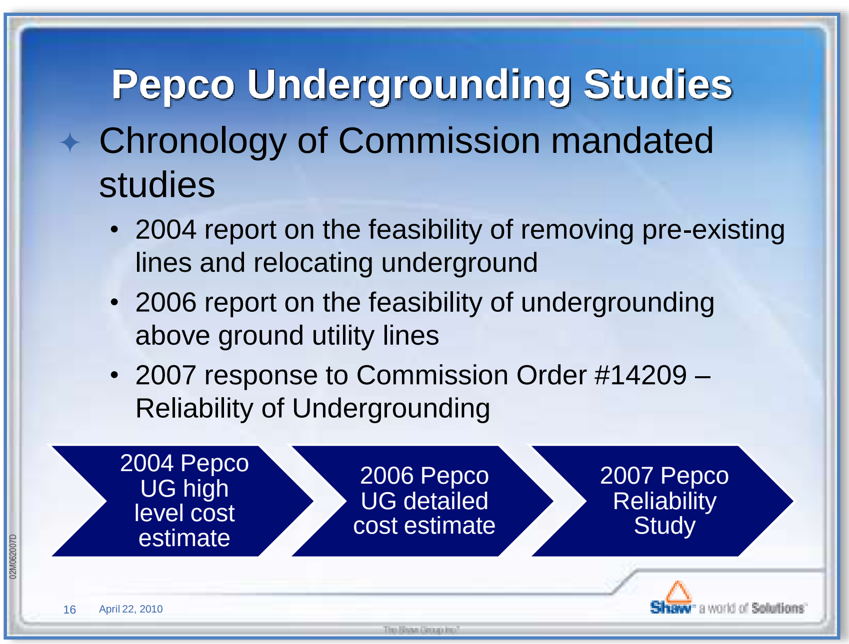
Putting Cables Underground (PCU) Working Group *Australia*	
	undergrounding including reduced tree trimming, pole inspections and replacement, reductions in transmission losses, and reduced maintenance. ▪ The report concludes that the decision to underground must be made at the right governmental level to achieve some economy of scale, finding that 1,000 homes is the smallest, most efficient size for a project. The study also found that the increased cost of electricity due to undergrounding can have negative effects on both downstream industries (large users) and upstream industries which provide inputs to electricity production. ▪ The Avoided Cost model is able to quantify the costs and savings, or avoided costs,, of overhead main line facilities in terms of $/km.
Cost Estimates	The total cost of putting existing overhead electricity and telecommunications cable underground in urban or suburban Australia was estimated at approximately $23 billion representing an average of $5,516 per household

3.3 Review of Studies Performed for and by Pepco

Central to our review of undergrounding costs, reliability, and other issues is an examination of recent Pepco studies that address the undergrounding of the distribution system in the DC Public Service Commission territory. We reviewed and analyzed the three reports dated 2004, 2006, and 2007, which were filed under Formal Case 1026 (the 2006 study was also under Formal Case 766). In addition Shaw Consultants reviewed the 2001 study regarding manhole explosions and the overall condition of their existing underground distribution system.

The three undergrounding studies were undertaken at the direction of the Commission and their chronology and content are depicted in Exhibits 13 and 14.

Exhibit 13 Chronology and Content of Pepco Undergrounding Studies



Key findings regarding these Pepco studies include:

- The 2004 study calculated an order of magnitude estimate of $4 billion for undergrounding the entire DC system.
- The 2006 study provided a more detailed estimate of undergrounding one feeder, and then extrapolated that estimate to fifteen feeders, for a cost of $1 billion, representing 13% of the then existing overhead system.
- The 2007 reliability study compared five of the worst performing overhead feeders to five underground feeders, and determined that reliability would be improved by moving those feeders underground.

Each of these studies is summarized in Exhibit 14.

Exhibit 14 Summary of Pepco Studies Reviewed

Year	Report	Driver	Methodology
2007	Reliability Analysis (Formal Case No. 1026)	Focus on reliability change with conversion from overhead to underground	Reliability study, comparing 5 worst overhead feeders with 5 existing underground feeders
2006	Detailed Cost Estimate for Undergrounding (Formal Case Nos. 1026 and 766)	Specific costs to underground versus magnitude of order estimate in 2004	Detailed engineering grade cost estimate for 15 feeders in DC
2004	Cost Estimate for Underground Conversion (Formal Case No. 1026)	Reliability in light of 2003 storms and outages	High level cost estimate for undergrounding DC system, using per mile costs
2001	Assessment of the Underground Distribution System of the Potomac Electric Power Company	Assessment of underground distribution facilities	Field inspections, interviews, review of Pepco studies, filings and practices

Assessment of the Underground Distribution System of the Potomac Electric Power Company (Pepco) 2001

The DC PSC engaged Stone & Webster Management Consultants Inc. (Stone & Webster) to assess the condition of Pepco's underground distribution system after experiencing several manhole explosions. Stone & Webster conducted field inspections, interviewed Pepco staff, and reviewed Pepco studies, filings and practices, reaching the conclusion that overloading was a primary factor in cable and splice failures that could lead to manhole fires and explosions.

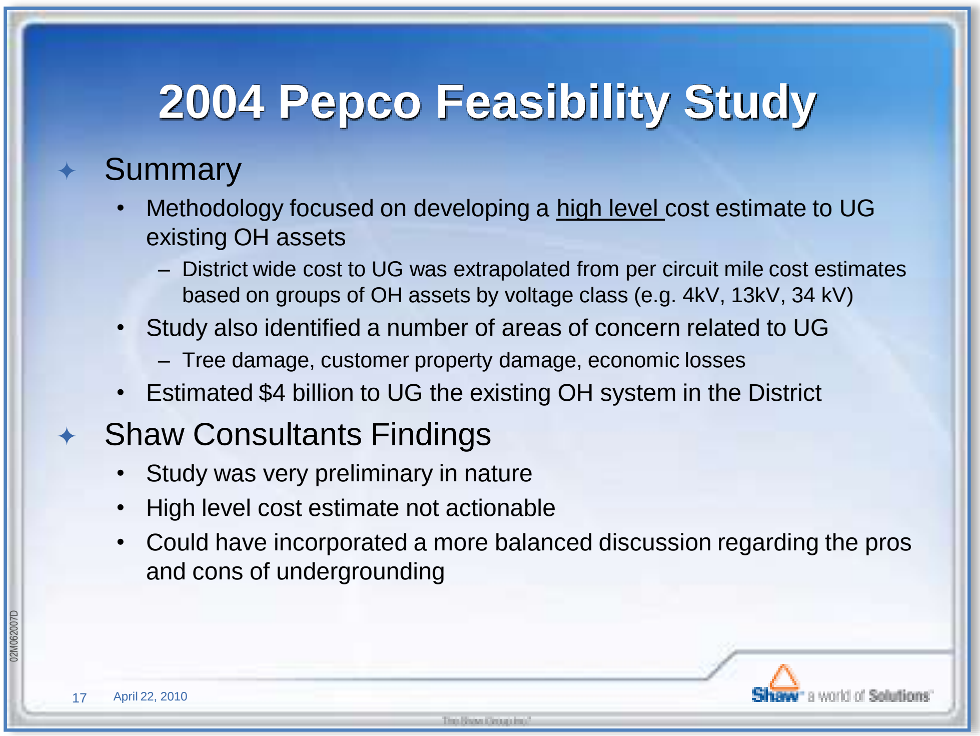
Stone & Webster recommendations included analytical modeling of the network system to determine overloaded portions of the system, performing a technical feasibility study of the application and installation of devices to limit current, and continuing to install a remote network monitoring system.

The study found that Pepco construction met or exceeded utility standards, as did the level of maintenance and inspections performed. The major concern identified was that the increased loading resulted in cable failures, causing explosions from gas build up in non-vented manholes.

2004: Cost Estimate for Underground Conversion (Pepco)

Pepco prepared a high level cost estimate of undergrounding its entire distribution system in the District of Columbia, estimating per-mile costs for 34 kV circuits, 4 kV and 13 kV distribution primary lines, secondary lines, and service drops using Pepco engineering estimates. The costs of installation of stand-alone service drops and removal of overhead equipment was also included. These per-mile costs were then multiplied by the actual miles for each category, resulting in a total cost of approximately $4 billion.

Exhibit 15 Pepco Feasibility Study, 2004



This study was very preliminary in the investigation of undergrounding for the District and did not fully present a balanced discussion of the pros and cons of undergrounding.

The study presented the advantages and disadvantages of both overhead and underground electric distribution as shown in Exhibit 16.

Exhibit 16 Advantages and Disadvantages of Overhead and Underground Construction

	Advantages	Disadvantages
Overhead	Lower cost Easier to install Less costly to maintain, repair and relocate Longer lived equipment Damage easily located	Susceptible to damage from vegetation Susceptible to damage from wildlife Susceptible to vehicle strikes Susceptible to lighting damage Susceptible to widespread damage during severe weather from tree demand and ice buildup
Underground	Aesthetics Less susceptible to damage from vegetation Less susceptible to widespread damage during severe weather Less susceptible to damage from wildlife	Higher cost More difficult to install More expensive to maintain, repair, and relocate Damage can be difficult to locate and time consuming to repair Damage due to excavation (dig-in)

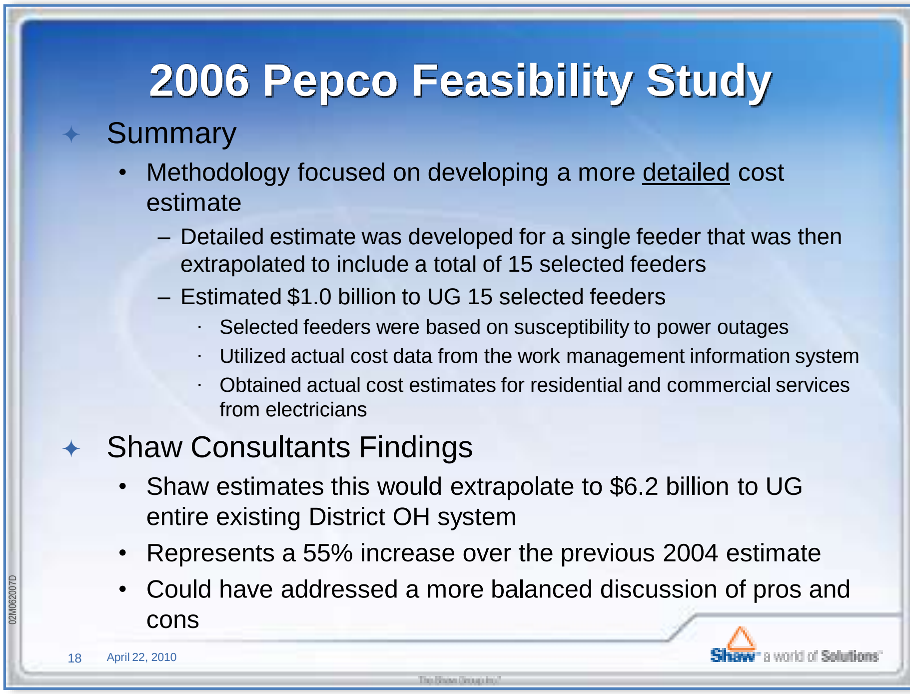
The study investigated moving primary and secondary overhead to underground, focusing on the DC area. This restricted the study to approximately 229,000 of Pepco's 720,000 customers. The DC study covered an area of 69 square miles, using one hundred and five 4 kV overhead circuits and one hundred and twenty four 13 kV overhead circuits. The study estimated that there are 633 circuit miles of primary in the District. In 2004 dollars, the resulting cost estimate for undergrounding was $4 billion. The per-mile costs were $3.5 million per mile for 34 kV sub-transmission lines, $3 million per mile for 4 kV and 13 kV primary lines, and $1.3 million per mile for secondary lines. Service relocations were estimated at $4,400 per customer.

The study discouraged going completely underground, citing cost, outage duration, and the reliability issues affecting underground service.

2006: Detailed Cost Estimate for Undergrounding (Pepco)

This study provided detailed cost estimates for undergrounding feeders in selected areas of the District that are more prone to outages. The estimates covered approximately 87.5 miles of feeders, representing fifteen feeders. To arrive at the estimate, a detailed cost estimate was calculated for one feeder, developing unit costs per mile; then those unit costs were applied to the other fourteen feeders. Costs were determined using Pepco's Work Management Information System (WMIS), with actual electricians' estimates obtained for undergrounding customer equipment. The findings from this study are provided in Exhibit 17.

Exhibit 17 Pepco Feasibility Study, 2006



The total cost for undergrounding the fifteen feeders was $1.06 billion, including both utility and non-utility costs. Pepco did not include any estimate of the expected reliability improvements that would result from the conversion of the entire or any portions of the feeders.

Pepco additionally prepared a detailed cost estimate for converting overhead to underground for the primary, secondary, and services for residential and commercial customers. The study focused on cost and feasibility in areas known to have reliability issues.

This study was the most logical and detailed estimate found in our research, using, for example, licensed electricians to estimate the cost of their work. The cost breakdown is summarized in Exhibit 18.

Exhibit 18 Approximate Undergrounding Cost Breakdown

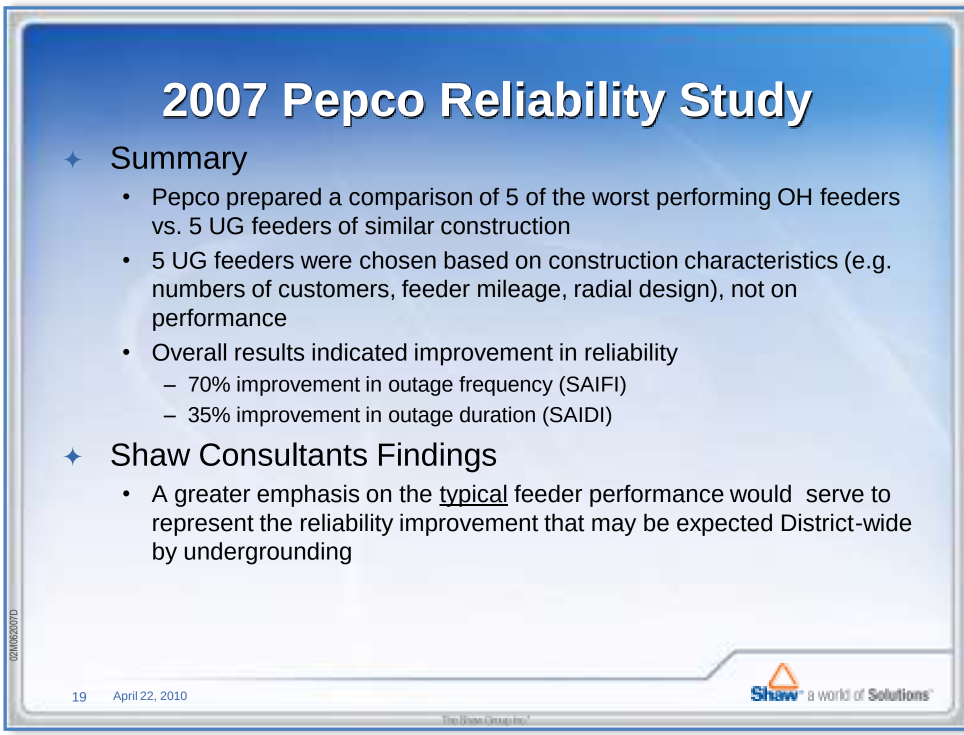
Service	Cost
Primary Mainline	$4,650,000/mile
Secondary Mainline	$24,000/customer
Commercial Service	$7,000/service for utility, $16,000/service by Customer
Residential Service	$10,900/service for utility, $2,200/service by customer
Street Light Costs	$316,000/mile
Permit Fees	0.38%
Removal Fees	0.77%

Reliability Analysis (Pepco) 2007

Pepco was directed by the Commission to revisit their 2006 study to estimate the reliability improvement in outage-prone areas if undergrounding were completed. This limited study selected five overhead feeders from the list of worst performers and compared those with five existing underground feeders. The results estimated that there would be 12 fewer outages per feeder per year. Results also showed a decrease in outage durations. Underground costs were estimated for the five feeders and a pure outage cost of $4 - 5 million was suggested.

Shaw Consultants concluded that the choice of the underground feeders against which the worst performing feeders were compared may not have accurately answered the reliability question (improvement versus cost) and may have skewed the results. Exhibit 19 summarizes the study and Shaw Consultants' conclusions.

Exhibit 19 Pepco Reliability Study, 2007



3.4 Examine Undergrounding Mandates and Practices in Other States

Shaw Consultants surveyed public service commissions in all 50 states, investigating existing mandates, issues, and practices with regard to undergrounding of power lines. We received responses from 40 states. In the five states where mandates exist, they address new residential subdivisions, requiring that all distribution lines in these subdivisions be placed underground. In six other states, individual municipalities require developers to place distribution lines underground in new residential subdivisions. In most cases, developers and customers are required to pay any incremental cost of undergrounding lines.

Our survey revealed that undergrounding is not an issue in most states. Many respondents reported that undergrounding is raised by customers after a storm does significant damage, but that the issue is abandoned once the costs of undergrounding are demonstrated.

A summary of our key findings from our state review are highlighted in Exhibit 20. Details of our interviews are provided by state in Exhibit 21.

Exhibit 20 Summary of State Mandates and Practices

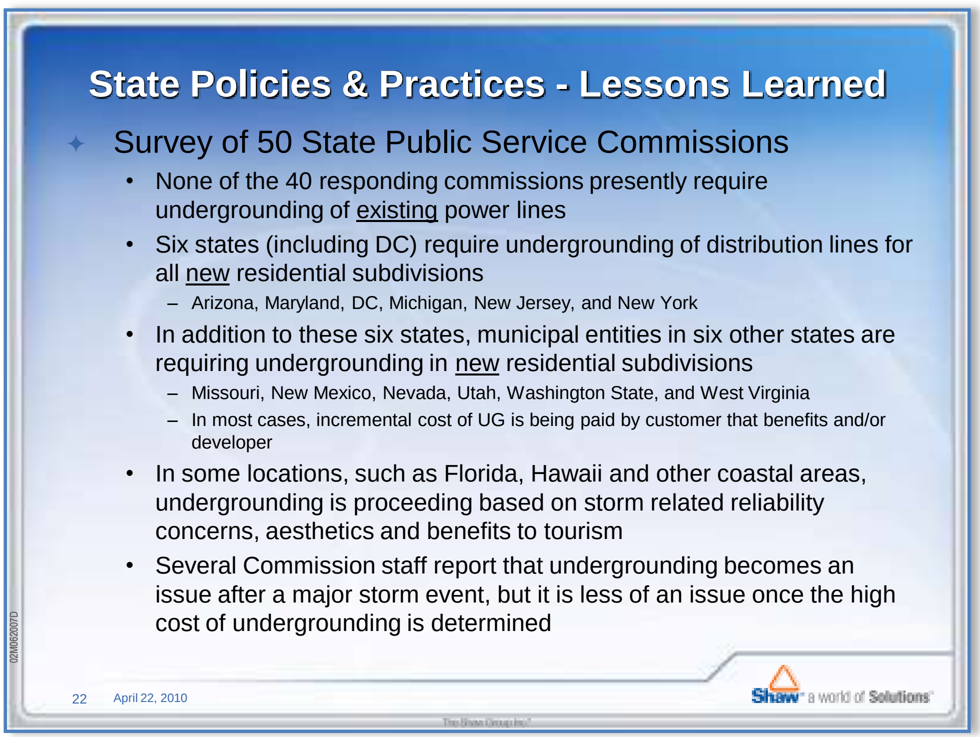


Exhibit 21 Summary of Interviews with State Regulatory Staff (Forty Responding States)

State	Existing Statewide Mandates	Undergrounding Issues Identified
AL	None	Incremental cost of UG paid by developer/customer
AR	None	
AZ	New subdivisions only	
CO	None	Incremental cost of UG paid by developer/customer
CT	None	
FL	None	Investor-owned utilities are required to have a process where customers opt for UG service and pay the incremental cost. For municipal utilities and cooperatives, the decision is left to local citizen boards.
HI	None	
IA	None	Incremental cost of UG paid by developer/customer
ID	None	Incremental cost of UG paid by developer/customer
IL	None	Incremental cost of UG paid by developer/customer
IN	None	
KS	None	Incremental cost of UG paid by developer/customer
KY	None	Recent storm damage has raised the issue of undergrounding
LA	None	
MD	New subdivisions only	
ME	None	Discussion of UG transmission due to concerns over EMFs
MI	New subdivisions and extensions of commercial or industrial lines	
MN	None	
MO	None	Some municipalities are requiring UG in new subdivisions
MT	None	Most new distribution being put UG, but not existing distribution
NC	None	Placing new facilities underground
ND	None	
NE	None	
NH	None	UG being discussed due to recent storm damage
NJ	New subdivisions only	
NM	None	Some municipalities are requiring UG in new subdivisions

State	Existing Statewide Mandates	Undergrounding Issues Identified
NV	None	Some municipalities are requiring UG in new subdivisions
NY	New subdivisions only	
OK	None	Recent report recommends targeted hardening.
OR	None	
SC	None	
SD	None	Incremental cost of UG paid by developer/customer
TN	None	
TX	None	
UT	None	Some municipalities are requiring UG in new subdivisions
VA	None	
VT	None	
WA	None	Some municipalities are requiring UG in new subdivision.
WI	None	
WV	None	Some municipalities are requiring UG in new subdivisions

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4 Reliability Assessment of Undergrounding

The purpose of this task is to gain an understanding of the present District of Columbia electrical distribution system including its design and engineering criteria, planning processes, maintenance practices, outage reporting, and asset performance and reliability statistics. Understanding this information is key to using the Pepco data to evaluate the potential for reliability improvement from adopting an undergrounding policy. The Shaw Consultants team met with Pepco personnel to understand the present outage management system, including outage records kept, availability of asset records, standard reports, design criteria, and reliability improvement plans and processes.

This knowledge was necessary in order to apply Shaw Consultant's methodology to demonstrating a correlation between the different types of construction in the Pepco service territory and the outages as an enhancement to Pepco's efforts in its prior studies. As noted in the previous section, the 2007 study had compared five of the fifteen worst performing overhead feeders to five existing underground feeders based on similar construction characteristics (e.g. numbers of customers, feeder mileage, radial design) rather than comparing typical feeder outage performance between overhead and underground, which Shaw Consultants believes is a better approach to assess the potential District-wide outage performance to be expected from an undergrounding effort.

To analyze the trends in outage performance in the District, Shaw Consultants selected ten representative or typical feeders based on 2008 System Average Interruption Frequency Index[1] (SAIFI) and Composite Performance Index (CPI)[2] data provided by Pepco. Five feeders were selected based on SAIFI and an additional five feeders were selected based on CPI. The five SAIFI feeders were selected based on the average SAIFI performance for feeders that had outages, making sure to include a cross section of construction types. This resulted in two feeders that are primarily overhead, one that is totally underground, and two that are a combination of both overhead and underground.

The remaining five feeders were selected based on Pepco's CPI ranking which ranks feeders sequentially based on a combination of outage frequency and duration. Since the average of a ranking would not be meaningful the median was used to select representative feeders, again making sure to include a cross section of construction types. This resulted in one completely underground feeder, two primarily underground, and two primarily overhead.

Shaw Consultants analyzed these ten representative performing feeders for a five year period to determine the frequency and duration of outages, and related these outages to the type of construction (overhead versus underground) assets involved to develop a model of expected failures per distribution asset type. To establish a level of improvement that may be realized from undergrounding, these statistics were compared and contrasted. The improvement is then applied to all Pepco overhead assets to develop representative estimates of reliability improvement. The analysis also includes a review of the 15 Worst Performing Circuits to assess those areas of the District that might serve to provide the most improvement initially.

[1] SAIFI - System Average Interruption Frequency Index. IEEE defined measurement for electric utilities designed to give (common) information about the average frequency of sustained interruptions per customer served in a predefined area.

[2] CPI – Composite Performance Index. A measure used by Pepco to further evaluate and rank feeder performance based on combining the number of incidents, customer hours of interruptions, SAIFI and the average interruption duration (SAIDI). This allows for a ranking based on all these statistics.

This section describes our analysis of reliability statistics, and develops an expected improvement in reliability from undergrounding the existing overhead assets in the District, and summarizes the existing Pepco reliability programs.

4.1 Analysis of Reliability Statistics

This section focuses on the feasibility and potential reliability improvements attainable if overhead assets were to be placed underground in a manhole and duct system (direct buried primary is not feasible for this type of project and the urban nature of the Pepco District service areas). The three main areas investigated were:

- The expected reliability improvement for both the average Pepco overhead feeder assets and the current 2008 WPFs against a sample of average performing feeders' performance over five years. Addressed in this Section.
- The use of the high level estimates of the various underground alternatives to fairly portray the costs against the expected benefits. Addressed in Section 5.
- The alternative underground construction approaches that could be employed to improve reliability and also minimize costs. Addressed in Section 6.

In order to assess the improvement in reliability that may result from adopting an underground construction approach in the District, Shaw Consultants reviewed Pepco's approach as utilized in previous studies and adopted an approach that improved on the prior analysis. As indicated earlier, Shaw Consultants developed a comparison of 10 representative or typical performing distribution feeders based on their SAIFI and CPI characteristics. For these ten feeders, we reviewed five years of outage event history including comparison of overhead to underground, primary versus secondary, and non-storm compared to storm performance. Our team calculated the outage frequency on a per circuit-mile basis so that reliability implications of the selected circuits could be used to estimate system implications; we also calculated the average outage duration for the typical feeders (CAIDI). This approach provides a more useful measure of the anticipated improvement from a move to undergrounding on a District-wide basis because it is based on typical circuit performance and not on type of construction.

The average feeders and their performance were used as a predictor of the expected reliability improvement that could be obtained by placing overhead assets underground. Underground assets also experience failures and this difference in average performance represents the expected performance improvement (or degradation). Customers are affected not only by outages, but also by the time it takes Pepco to respond to an incident, locate the cause, make repairs and restore service. Both of these factors are important in making a determination of the benefits associated with rebuilding and relocating existing delivery assets.

4.1.1 Assumptions

Some assumptions were required to allow for the completion of the work in a timely manner. Shaw Consultants developed asset performance based on the then available Pepco records and information provided by Pepco to develop interruptions on a per circuit-mile basis. Based on the quality of the records, the following assumptions and/or decisions were made and used.

- *Faults were calculated based on circuit-miles.* There are two generally accepted measurements for the line assets a utility operates: wire-miles or circuit-miles. Wire-miles use the total amount of wire in the air or underground; if an area has three phase construction (three primary wires) on a street running for 1 mile, this would be 1 circuit-mile or 3 wire-miles. Because exposure to damage is not greatly increased by three (wires) phases running by a tree as opposed to a single (wire) phase, our analysis is based on circuit-miles.

- *Primary wire and construction types.* For the overhead portions of the sample feeders and the 2008 WPFs, information about how the lines were constructed – covered or bare wire, open arm or spacer, etc. – was requested. Typically this information is stored in a utility's GIS system for use in calculating circuit characteristics e.g., resistance, induction, fault current. Pepco does not yet have this information in their electronic system, so it was not available. Many of the tree incidents, especially the 2008 WPFs, were recorded as having occurred on covered wire, but a focus on the long term advantage of covered wire was unavailable. For the study there is no distinction made for overhead covered wire and bare wire as to the expected incidents per mile.
- *Secondary circuit-miles.* Overhead secondary was estimated at the same length as overhead primary circuit-miles. The overhead primary may originate from a substation and run to a feeder area without accompanying secondary. But secondary is often on poles where no primary is required; we assume that these essentially offset for these estimates of occurrences.
- *Transformers*. Pepco provided, by circuit, a list of transformers used to supply its customers. When reviewing the 5 years of outage history used as the base case, there were a few transformer outages indicated and there were a minimal number of customers involved; these were repaired with a fuse being replaced but with no reference to changing out the failed transformer. This would indicate another cause of the outage, such as an animal contact at the transformer bushing or a shorted/grounded secondary cable, rather than a failed transformer. Transformer fuse replacements were included in the primary outages, unless there was a clear indication otherwise. Based on this information, indicating minimal transformer issues, transformers were not a significant focus of the reliability improvement possibilities.

4.1.2 Selecting Representative Feeders

In selecting the representative feeders, we analyzed the circuit length, the percentage of overhead versus underground construction on the feeder, and verified the details of the reported outages during the past five years to ensure consistent information for comparison. We selected circuits with light, medium, and heavy vegetation using Google Earth as a virtual visit to the geographic areas.

To select the ten average feeders, Shaw Consultants reviewed lists of feeders in the District for the 2008 reporting year[3]. These lists had been sorted based on certain performance measures, including SAIFI and CPI, to determine a ranking based on outages and duration of events. Shaw Consultants' review focused on SAIFI, which best represents how one feeder compares to other feeders. We included feeders with average SAIFI scores for the District in our average feeder analysis. Pepco uses a CPI sorting system to analyze and further rank feeders based on the number of events and the average restoration time for each event. We included feeders in our average feeder analysis based on their CPI score, because CPI is Pepco's method of selecting its Worst Performing Feeders (WPFs).

We selected a cross-section of feeders, including overhead, underground, and combination feeders (those with both overhead and underground portions) that were near or at the average (with a SAIFI sort) and the median (with a CPI sort). The 2008 records included several major events (storms). These

[3] Reporting year for 2008 outages and the resulting reliability is October 1, 2007 to September 30, 2008.

events have been included in our findings of events and durations, and allow us to present a typical operational period of 12 months. We then compared this period to a five year (60 month) detailed analysis of actual asset performance. Heavily treed overhead areas are often more prone to storm damage from ice and wind; this is factored into our model through the use of the 5 year history of the ten feeders and of the entire Pepco District service territory and our selection of feeders in lightly, medium and heavily treed areas.

While investigating these ten feeders in detail, it became apparent that large annual fluctuations can occur on any particular feeder. One of the ten feeders went from an average of nine overhead incidents per year (2004–2007) to forty three overhead incidents in 2008 (feeder 15174), mainly due to localized micro-storms/energy burst that year. We used a five year average to develop a more complete and accurate model of the expected performance to better account for unusual reliability performance. This feeder had a SAIFI of 3.87 for the 2008 reporting year. For the five years (2004-2008) with all incidents included the average SAIFI is 1.43. Many of the feeders investigated had some abnormal data and history for specific periods, but over the 5 year period, the reliability performance was smoothed and reflects a more normal performance, including these up and down performance years.

Methodology for selection of Ten Typical Circuits (or Feeders)

Step 1: Identify five average feeders in 2008 based on SAIFI. To select the first five feeders, we used the average SAIFI of all feeders that had outages; some feeders had no incidents and were not included in the analysis. The average SAIFI for reporting year 2008 for feeders in the District with outages was 1.26 outages per year. Five feeders that had a SAIFI nearest to 1.26 were selected, making sure to include a cross section of field assets. As a result of this selection process:

- 2 feeders are primarily overhead (approximately 97%)
- 1 feeder is 100% underground
- 2 feeders are a combination of overhead and underground.

The customers represented in this selection process included a total of 2,279 overhead customers and 1,058 underground customers; this compares to the total service by Pepco in the DC area of 80,000 overhead and 160,000 underground customers, including the network system.

Step 2: Identify five average feeders in 2008 based on CPI. To select the other 5 feeders, Shaw Consultants used Pepco's CPI sorting and prioritization system to identify candidates for the Worst Performing Feeders (WPF) in the system. The CPI system takes into consideration factors such as the number of interruptions on a feeder (the number of affected customers is not considered), outage hours, System Average Frequency and System Average Interruption duration. The median of the CPI scores was calculated and feeders in the vicinity of that median score were selected, again attempting to get a cross section of system assets. This process resulted in:

- 2 underground feeders (one 100% underground and the other 91% underground)
- 3 mixed feeders, two predominantly overhead and one predominantly underground.

The customers represented in this selection process included a total of 2,106 overhead customers and 204 underground customers.

In order to assess the improvement that may be possible, it was necessary to select a representative set of feeders with poor performance. We investigated the 15 worst performing feeders (WPF) for 2008 as submitted in Pepco's 2009 Consolidated Report, initially identified and prioritized using a CPI sort then further reviewed and sorted to eliminate WPFs from previous reports which were undergoing upgrades. The 15 identified WPFs had a total of 380 outage events. These statistics were also categorized by cause and by asset class.

The WPFs were analyzed to determine how far they deviated from the 5 year average, both by causes and by number of events. For example, if 13 kV primary averages 2 outage events per year per circuit-mile and a WPF has 12 circuit-miles, we would expect (on average) to have 24 outage events. Statistics provided later in this section document the WPFs performance as compared to the ten average feeders.

4.1.3 Data Availability and Quality

The results of this review, study and recommendations are based to a great extent on the data Pepco made available from its customer records and records of outages, the latter entered by overhead and underground crews.

Customer Information - Connected Electrical Model

As part of the study Shaw Consultants requested, for the sample 10 feeders and the 2008 WPFs, the number of customers served from the overhead and the underground systems by feeder, the number of customers on mainlines (3 phase), and those on laterals (either 2 phase or single phase). We requested similar data for all 750 feeders that serve the District, to understand the reliability indices by delivery type (overhead versus underground) with and without storms. We further requested a breakdown of underground delivery assets (network, radial, etc.). This type of data has been included in Pepco's filings to the PSC[4] in previous years. This data was not available prior to the conclusion of the study. Estimates of customers affected provided in this document are based on summary public information.

Outage Information

There were some data issues that are very typical (at most utilities) in documents prepared/entered by repair and restoration personnel who are focused on working energized lines safely and moving to the next incident or assignment as opposed to completing reporting documents. In most cases, where there was incomplete or inconsistent data, our team was able to mine the correct information by correcting the data and using "virtual" site visits to examine the electric facilities at the outage location. The one exception was outages that had complete information for only a location and unknown for the various causes and assets involved. For these Shaw Consultants indentified the area as being served OH or UG and based on the customer count, categorized the outage as either primary or secondary. To clarify Shaw Consultants' tools and assumptions:

- *Outages with incomplete data as to affected asset – primary or secondary.* The number of customers affected was used to determine if the fault was more likely a primary or secondary incident, with a single transformer used as the crossover. Virtual visits were also made to the location to see if primary existed on the pole, if an OH location.
- *Bad outage data – customer's involved.* Several times in reviewing outage data we found, regardless of incident cause, customer counts that had obviously bad data. For example, a feeder that serves 1,150 customers had an outage that listed 3,400 customers as being affected.

[4] Report on the Feasibility of Removing Pre-Existing Aboveground Utility Lines and Cables and Relocating them Underground – September 30, 2004, Page 12, Table 2

Even if the feeder was temporarily carrying load on adjacent circuits, the customers served would show additional customers as it is not possible to interrupt more customers than are served. This type of error was corrected to include up to the number of customers served. Other incidental bad data which included items such as street light outages was disregarded.

- *Multiple outages listed for one incident.* While analyzing the 5 year outage data for the 10 selected average feeders, cases were discovered where outages were split and listed as multiple incidents. We recognize the need to separate outages if the restoration times of an event are different for groups of customers. However, when the grid location, the incident start time, and restoration time are all exactly the same on the same day, we reported this as one event not three or four events. As we are measuring the incidents per mile, this type of incident recording over-states events and distorts the record. Examples can be found on Feeder 15174 in the 2008 outage records. For this study these events were re-grouped into a single incident. We note this has no effect on feeder SAIFI as customers are split and time recorded for each; however as the Pepco CPI system includes events as an indicator of performance, this could overstate the seriousness of the outages on a feeder in the ranking. As changes are made in the OMS system and the DATA Mart is replaced, we recommend a program be developed to look for similar events by feeder, date, grid location, time of event, and the restoration time to check data integrity.
- *Incident not specified as OH or UG.* On totally UG feeders this was not an issue, but on combined feeders (partial OH and partial UG), we converted the Maryland plane data to the GPS coordinates and using internet tools such as Google Earth "flew" to the site to view the electric distribution assets in the area and at the site. This was very successful and we were able in all cases to make this determination.
- *Illustrative Sample (refer to Exhibit 22) of Shaw Consultants' use of Google Earth to separate UG from OH assets identified in outage incidents*.

  Pepco Data provided as:

  Circuit 14200 – Outage 6/16/2008 – XFM 796398-598026 Maryland [NAD27]

  Translates - Easting 796598 feet and Northing 398026 feet of reference point

  Google Earth translation to map:

  Translates to GPS - Longitude 77 degrees 0 minutes 43.049 seconds – West

  Latitude 38 degrees 55 minutes 34.597 seconds – North

  Produces the photo in Exhibit 22 which could be manipulated to observe the type of construction – OH or UG.

Exhibit 22 Pepco Assets, Google

- *Bare or Covered wire not specified:* Similar to the method used to determine if the area was OH or UG, our team attempted to determine if the OH lines were bare or covered. The Google photographs were not clear enough and many were affected by sunlight and made this difficult to determine. Some outage reports do list, for OH primary outages, if the wire was bare or covered, but most do not. Other utilities track the installed field assets using the GIS system to determine if the primary wire is bare or covered, open arm or spacer cable, for example, for tracking asset performance, calculating system characteristics for setting relays and voltage regulation, and recording accurate outage information. Pepco does not currently have this information in their GIS system.
- *Incident cause not identified*: Many outages had no cause or repair information specified to allow categorizing of the outages. This was true for both the UG and the OH incidents. In most cases, we were able to determine (by construction and customer counts) if the problem was primary or secondary for the outages. To include all outages, those not strongly identified as a secondary outage were included as a primary incident.
- *Data event disagreement*: The "2009 Consolidated Report" filed by Pepco, reports on page 144, that there were "No Major Event Interruptions in 2008". However page 142, of the same report, lists "Major Event Days" on February 10th, May 31st, June 4th, 5th, and 16th, 2008. For this report we used the event days listed on page 142 when calculating the performance of feeders for both storm and non-storm days.

4.1.4 Outage Data Development

To determine a baseline for the potential reliability benefit of placing OH assets below ground Shaw Consultants identified ten sample feeders that were "average performers" across the total population of the ≈750 Pepco District feeders. The feeders were selected based on their 2008 reporting year performance, as these feeders would have experienced much the same environment as all 750 District feeders.

The average feeders were selected using two different mean scores: the annual SAIFI calculation for the feeders, and as Pepco identifies the WPFs using their unique CPI, Shaw Consultants used the 2008 final CPI District feeder ranking that was prepared for selecting five of the feeders. Once the mean was identified for the range of feeders that had any outages up to the WPF categories of performance the mean feeders were selected.

Pepco serves approximately 240,000[5] customers in the District of Columbia, of which approximately 80,000 customers are served with services from overhead distribution. Approximately 1 of every 3 customers is presently served from OH lines. To best develop an analysis tool, it was important to select a mix of overhead and underground assets represented in the sample to compare performance per circuit mile and customers served from the overhead and underground systems. If the underground is a more reliable system, then to choose predominately underground feeders for the sample would not be able to show the expected benefit as the sample group would be distorted. As most problems in the District are associated with the OH lines, it was important to look a little harder and longer at these outages to see what, if any, pattern existed and how the Pepco response was in both storm and non-storm situations. Therefore, our selection process of the average feeders was done so that OH customers would be fully represented.

As a result, the selection of the sample feeders was focused on a cross section of distribution feeders that use OH and UG assets to deliver power clustered around the mean of the performance of the District system. The sample group selected consists of:

- 2 - 100% underground feeders (Feeder 76 and 15294)
- 2 - Overhead feeders[6] (97%) (Feeders 308 and 366)
- 3 - Blended feeders predominantly OH (Feeders 14896, 14755, and 15174)
- 2 – Blended feeder predominantly UG (66 and 229)
- 1 - Blended feeder with relatively equal OH and UG line portions (14133)

Five of these feeders are 4kV (indicated by 2 or 3 digit identification number), and many UG 4kV feeders are on the list for conversion to 13kV in the near future. Three of these feeders have appeared on the WPF list in recent years: 308 in 2008, 14896 in 2007, and 14755 in 2002.

For the OH feeders, it was recognized that many of the District outages were caused by tree contact and tree failures. Therefore, selection of feeders that are primarily OH used previous outage locations to virtually visit locations and capture various tree conditions in the service territory. Of the OH feeders involved in the 10 average the tree cover falls into three categories: lightly treed, moderate tree cover, and heavily treed. Exhibits 23 through 26 depict examples of areas in each of the categories.

[5] Shaw Consultants rounded customer counts to the next even 1000 in order to account for variations in the counts received during the investigation.

[6] 100% overhead primary feeders are rare as the Pepco OH system will typically feed into an underground housing area or an underground business park or shopping center.

Exhibit 23 Heavily Treed Areas – Feeder 14896 near 6330 Utah Ave. NW

Exhibit 24 Heavily Treed Areas – Feeder 14133 near 2936 Brandywine St. NW

Exhibit 25 Moderately Treed Areas – Feeder 366 Near 25 53rd St. SE

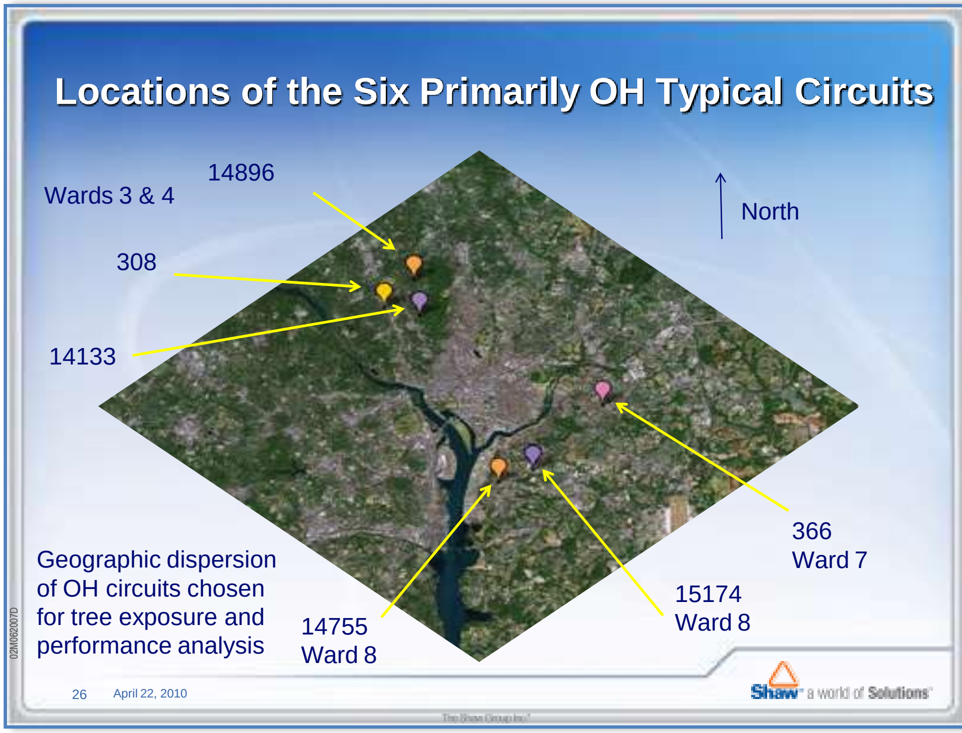
Exhibit 26 Lightly Treed Areas – Feeder 14755 near 200 Wilmington Pl. SE

The selection centered on the performance average of the SAIFI statistic and the median of the CPI populations; we selected circuits on both sides of the average and median, selecting the first feeders that met the OH versus UG asset groupings' criteria until the 10 were selected.

We note that there are two different source data years – the Pepco 2008 Reporting Year that captures events from October 1, 2007 to September 30, 2008 and there is also the standard January – December calendar year. The reporting year was utilized for the selection of the 10 feeders initially to allow for a realistic comparison with the WPF feeders to answer the question as to whether the 2008 reporting year was unique due to unusually fair or inclement weather. As the results of our analysis show, the 2008 reporting year was average with some small storms but no major multi-day events from major storms such as a hurricane. The indices for the 10 average feeders were calculated, for comparison purposes, first including the last three months of 2007 and then dropping the last three months of calendar 2008. No anomalies were found that could justify eliminating either the 5 year average investigative method or any individual feeders.

Since tree damage is a major contributor to overhead outages it is important to understand the geographic representation of the feeders selected which is depicted in Exhibit 27.

Exhibit 27 Geographic Locations of Primarily OH Typical Circuits



4.1.5 Outage Analysis Methodology - Typical Feeders

Based on the 2004-2008 outage reports supplied by Pepco and research of these outages using virtual field visits, the team analyzed the ten average feeders to develop a 5 year average performance baseline. This performance is developed based on the sustained incidents that cause service interruptions to one or more customers on a per unit basis: in this case, incidents per mile.

The outages were broken down according to the three major types of construction as reported in the Pepco OMS system reports: overhead, traditional underground, and underground residential distribution (URD) and then further broken down as to whether the fault involved the primary conductors and equipment or the secondary conductors and the related equipment. These outages for each of the 10 average feeders for the five years were also separated if they occurred on a Significant Major Event Day as listed in the 2009 Consolidated Annual report.

Due to the quality of the outage data supplied by Pepco, approximately 10% of the outages had little useable data associated with the outage. This lack of information was in two major categories – whether the area's construction was OH, UG, or URD, and whether the outage was a primary or secondary event

An analysis of the five year data was completed to assess the most likely construction type in the area which utilized the number of customers involved (if necessary) to determine whether the outages were in the primary or secondary portion of the distribution system. As mentioned previously, we were able to use the Pepco grid (locating) system and translate it to the current GPS standard so that we could visit the location on the internet, and in all cases we were able to determine the construction in the area. Based on this information and the number of customers involved (primary versus secondary), the incidents per mile of OH and UG construction was developed. Since this study is a review of previous studies on the feasibility of moving OH assets underground and the resulting reliability change, assets were grouped into OH or UG (which contains all assets physically located below ground - UG & URD) for this analysis.

As trees are a major cause of outages, the five year review ensured that the OH feeders in the study would have had at least two trimming cycles, as Pepco is on a two year (trimming) cycle; a five year average allows for a minimum of two but possible three trim cycles. Finally, weather patterns vary from year to year, and by using five years the analysis allows for a fair representation of weather conditions across the Pepco District service area.

The five year analysis was focused on calculating the average incident rate per mile of OH and UG primary and secondary per year over the five year period. The calculations were completed with and without storms, specifically those storms listed in the 2009 Annual Report that are exempt from inclusion in "normal weather days" in the reliability calculations (major event days). The data for the storm events was also gathered, analyzed, and categorized as these events will also be compared for potential improvements in placing the assets underground. Based on this philosophy, data, and tool set this study:

- Investigated and determined the miles of primary OH and UG from the Pepco GIS system and converted the wire-miles into circuit-miles of exposure for each feeder.
- Identified each feeder by the portion of the feeder that was OH and the portions that were underground; for example, the feeder might be 100% underground or it might be 75% overhead and 25% underground. There were no feeders identified that were 100% overhead, as each had some small portion of underground customers and lines.
- Recognized that many of the outages involve the secondary distribution system that travels from the transformers along the street and into homes and businesses. To again measure the incidents per circuit-mile, the analysis estimated the circuit-miles of secondary conductor as the same length as the primary.
- Analyzed for each feeder, every outage through the years 2004 – 2008 based on the data supplied by Pepco. The total number of incidents analyzed over the five years was 628 total incidents (485 overhead incidents and 143 underground incidents) that caused electrical outages.
- Sorted the outages by overhead versus underground, primary and secondary, and storm versus non-storm periods. From this *an annual average* was determined for each feeder for the overhead and underground portion, primary or secondary, and if it was during an exempt major event (storm).
- Developed average incidents per year from the five year data and average per circuit-mile for all feeders.
- Focused on calculating the average incident rate per mile of OH and UG primary and secondary per year over the five year period. The calculations were done with and without storms, specifically those storms listed in the 2009 Annual Report that are exempt from normal inclusion in the reliability calculations.
- Analyzed the 10 average feeders for the period October 1, 2007 thru September 30, 2008 to ensure appropriate selection of the feeders.

2008 Reporting Year Typical Feeder Statistics

For the 2008 Reporting Year (October 1, 2007 – September 30, 2008), the summary performance statistics for the 10 average feeders are provided in Exhibit 28. Use of the 2008 reporting year maintains consistency with the worst performing feeders because that data is based on the reporting year, as opposed to calendar year. Exhibit 28 includes all events, non-storm and storm, and because the 2008 Pepco Consolidated Report excludes storm events when reporting these numbers, the statistics calculated below are higher than Pepco's numbers.

Exhibit 28 Summary Statistics for Ten Average Feeders, 2008 Reporting Year

Average Feeders	SAIFI	CAIDI	SAIDI	Circuit-Miles OH	Circuit - Miles UG	Percentage OH	Percentage UG
Selected For Average SAIFI versus Pepco District Feeders							
14133	1.27	166	210	5.2	4.8	52%	48%
15174	2.89	291	839	5.1	2.1	71%	29%
15294	1.40	225	314	0	4.9	0%	100%
366	1.38	171	236	3.2	.1	97%	3%
308	0.81	324	263	3.6	.1	97%	3%
Selected For Being the Mean of the Pepco CPI index							
66	1.02	120	123	.1	1.1	9%	91%
76	1.32	106	140	0	1.6	0%	100%
14755	1.55	271	421	3.6	1.1	76%	24%
14896	2.34	387	905	11.8	1.5	89%	11%
229	1.49	295	440	.8	2.9	22%	78%
				33.4 miles	20.2 miles	62% OH	38% UG

Using the circuit miles of exposure, an examination of the number of incidents per circuit-mile for the 10 average feeders for just the 12 months of the 2008 Reporting year resulted in the statistics shown in Exhibit 29.

Exhibit 29 All Incidents, 2008 Reporting Year

Average Feeders	OH Incidents	UG Incidents	Circuit-Miles OH	Circuit-Miles UG	Incidents Per Circuit-Mile OH	Incidents Per Circuit-Mile UG
Selected For Average SAIFI versus Pepco District Feeders						
14133	17	4	5.2	4.8	3.3	0.8
15174	53	0	5.1	2.1	10.4	0
15294	0	9	0	4.9	0	1.9
366	11	0	3.2	0.1	3.4	0
308	14	0	3.6	0.1	3.9	0
Selected For Being the Mean of the Pepco CPI index						
66	0	3	0.1	1.1	0	2.7
76	0	11	0	1.6	0	6.8
14755	22	1	3.6	1.1	6.2	0.9
14896	42	0	11.8	1.5	3.6	0
229	0	3	0.8	2.9	0	1.0
Average Incidents per mile 2008 Reporting Year					**4.8**	**1.5**

This statistical representation indicates that for the twelve months that are included in the 2008 reporting year, the 10 average feeders, when all outages (storm and non-storm) are included, experienced 4.8 incidents for every circuit-mile of OH primary and 1.5 for every mile of UG primary.

The largest contributor to the overhead statistics in the 2008 reporting year was the 15174 feeder which accounted for 53 OH incidents that year. When feeder 15174 is analyzed for the five years (a period that includes this same 12 month period) the feeder has a total of 80 storm and non-storm events for an average of 16 per year and an OH incident per circuit-mile factor of 3.1. Feeders do experience wide swings in their performance due to many factors including, for example, localized storms and tree trimming cycle impacts.

Five-Year History of Statistics for Typical Feeders

In comparison to the 2008 reporting year, the initial data for the five years resulted in the statistics depicted in Exhibit 30 for all primary, secondary and weather conditions.

Exhibit 30 Average Annual Performance, Ten Typical Feeders 2004-2008

Five Year Feeders	SAIFI	CAIDI	SAIDI	Circuit Miles OH	Circuit Miles UG	Incidents per Mile OH	Incidents per Mile UG
Selected For Average SAIFI versus Pepco District Feeders							
14133	1.67	221	368	17.8	2	3.4	.4
15174	1.43	193	277	16	1.2	3.1	.6
15294	.55	309	169	0	7.8	0	1.6
366	1.41	172	242	6.2	.2	1.9	2.2
308	1.41	178	251	9.4	0	2.6	0
Selected For Being the Mean of the Pepco CPI index							
66	1.05	299	315	1	4	9.1	3.5
76	.80	237	189	0	5.2	0	3.2
14755	.99	260	258	16.8	1.2	4.7	1.1
14896	3.26	260	849	27.6	1.2	2.3	.8
229	.83	330	272	2.2	5.8	2.7	2
Average Incidents per Mile per Year Average 2004-2008						**2.9**	**1.4**

These initial results for all the incidents from 2004 – 2008 show that when the overhead delivery system is compared to the underground system for all outages, primary, secondary, and storms, that the overhead customers will on average see 2.9 incidents per circuit-mile - this is roughly twice the number of UG incidents of 1.4 per circuit-mile. This 5 year average of all OH events is roughly 1.9 events per circuit-mile less than the events for just the 2008 Reporting Year. Underground is fairly consistent at 1.5 and 1.4 events per circuit-mile, respectively.

The statistical analysis also demonstrated that many outage incidents occur on the secondary of the overhead and underground systems. To better present this, the secondary of both the overhead and underground systems has been analyzed and credited with the number of incidents per circuit-mile calculated based on secondary circuits being equal in length to the primary circuits they are part of, not including house services. The results are shown in Exhibit 31.

Exhibit 31 Primary vs. Secondary Outage Incidents, Typical Feeders, 2004-2008

Outages	Primary	Secondary	Grand Total
OH	343	142	485
UG	70	55	125
URD	3	15	18
Total	**416**	**212**	**628**

As the study is a review of placing OH assets UG at this point the UG and URD incidents were combined into a common category to avoid confusion – for the remainder of this analysis there is either OH or UG construction.

The statistics for the typical feeders were separated into the assets involved, primary or secondary and the weather conditions, storm or non-storm related as well as OH or UG assets which yielded the statistics in Exhibit 32.

Exhibit 32 Average Annual OH vs. UG Outage Incidents, 2004-2008

Outages	Non-Storm Primary	Storm Outages Primary	Non-Storm Secondary	Storm Outages Secondary
OH	290	53	134	8
UG	73	0	69	1

Exhibit 33 provides the incidents per circuit-mile for the 10 average feeders, and it should be noted that the secondary for both OH and UG was estimated at the same length in circuit miles as the primary.

Exhibit 33 OH vs. UG Outage Performance Comparison Incidents per Circuit-Mile, 2004-2008

Outages	All Outages	Primary	Secondary	Non-Storm	Storm
OH	2.9	2.1	0.85	2.54	0.37
UG	1.4	0.72	0.69	1.41	0.01

The summary statistics in Exhibits 33 and 34 demonstrate the clear difference in the number of outage incidents between the two types of construction. Although overhead accounts for slightly more than twice the outages per circuit-mile as that evidenced in the underground feeders, the primary overhead feeders demonstrate three times as many incidents per circuit-mile versus the underground primary feeders. Similarly the storm based incidents per circuit-mile are significantly higher for overhead and negligible in the underground system.

The implications for customers are demonstrated in Exhibit 34, which shows that while storms caused approximately 20% of the customer outages, the CAIDI (or duration) for these storm events averages 5 hours longer than non-storm outages.

Exhibit 34 Customers Affected by Outages, Storm and Non-Storm

Five Year Average	All Outages	Non-Storm Outages	Storm Outages
Number of Customers	12,840	10,652	2,188
Hours of Outage	50,720	32,853	17,867
CAIDI - Hours per Average Event	3.95	3.08	8.17

Breaking out the affected customers into OH and UG primary and the secondary incidents, the results show that few customers are affected during storms by secondary outage issues (3) and that the major contributor to the SAIFI (outage frequency) are those incidents that occur on the primary circuits (2,185 storm and 8,573 non-storm) . The results are depicted in Exhibit 35.

Exhibit 35 Customers Affected by Asset, Storm and Non-Storm

Five Year Avg.	Non-Storm Outages Primary	Storm Outages Primary	Non-Storm Outages Secondary	Storm Outages Secondary
OH	8,573	2,185	52	3
UG	1,982	0	45	0.2

In one of the average years for the ten feeders, secondary accounts for less than 1% of the customers with an outage and during storms that drops to 0.15%. *This indicates that placing secondary UG for improved reliability as well as moving all the OH services UG will bear very small reliability gains.*

The significant statistic during storm outages is the duration (CAIDI) of the average outage which is 265% greater, as contrasted in Exhibit 36 using Hours of Outage per Customer; this is due to operational and restoration issues, typically the work is the same as during non-storm outages, only there is much more of it to complete in a significantly more compressed period.

Exhibit 36 Total OH Customers Affected by Outages, Storm and Non-Storm

Five Year Average	Non-Storm Outages	Storm Outages
Number of Customers	8,625	2,188
Total Outage Hours	23,957	17,867
Hours/Customer	2.80	8.2

Similar results can be demonstrated for UG (Exhibit 37) - the customers affected by storm and non-storm events indicate quicker restoration for storm events – however there was only *one event*! More significant is the CAIDI of 4.4 for UG as opposed to the CAIDI of 2.8 for OH events during all non-storm events.

Exhibit 37 Total UG Customers Affected by Outages, Storm and Non-Storm

Five Year Average	Non-Storm Outages	Storm Outages
Customers	2027	0.2
Hours	8896	0.56
Hours/Customer	4.4	2.8

Analysis of the 10 Average Feeders - Results

The ten average performing feeders over the five year period for the combined OH and UG have a SAIFI of 1.3 – the average customer would have 1.3 outages per year, as with all averages some would see more and some less. The average outage duration over the five-year period (CAIDI) is 3.95 hours (see Exhibit 34). One of the feeders selected based on the 2008 reporting year CPI was feeder 14896, which had been a WPF in 2006 and has a relatively high SAIFI (3.26) compared to the other nine feeders, demonstrates that the selection process was fair - showing circuit performance will produce variations in results as would be expected.

To summarize, several conclusions from the analysis of the 10 average feeders are evident:

- Significant outage incidents that involve large groups of customers and drive the SAIFI index higher are associated with both the OH and UG ***primary*** assets.
- Secondary incidents, while recognized as a great inconvenience for those customers involved, are insignificant in the total numbers of customers affected and also the typical feeder SAIFI (frequency). Of the 628 total outages, 64,198 customers were affected on the 10 typical feeders during the five-year period, yet only 495 customers were out for secondary failures (0.77%).
- The average annual incidents per circuit-mile of **combined** primary and secondary are 2.9 incidents per circuit-mile of overhead construction and 1.4 incidents per mile of underground construction for the ten typical feeders. The incidents per circuit-mile are based on *any event that took out any number of customers due to any cause for various durations and repair activities.*
- The CAIDI (duration) analysis for various events demonstrates that on average for non-storm events, the OH was repaired and restored in an average of 2.8 hours while UG repairs took on average 4.4 hours to complete. However, during storms the OH CAIDI increased to 8.17 hours while there were no UG storm related failures for comparison.
- Based on this review of existing data, secondary assets have a small effect on the total outage events and duration of the outages that the majority of customers experience. Any significant improvement in the performance of the District feeders will depend on making improvements in the overhead primary distribution system. These conclusions are reached absent recognition of the cost differential in underground versus overhead construction. This topic is addressed in Sections 5 and 6.

4.1.6 Analysis of the 15 Worst Performing Feeders

This effort also analyzed the WPF feeders, using the incidents per circuit-mile of OH and UG for both primary and secondary, as this was the only information initially available for this effort, and has been included here to demonstrate the potential for improvement of placing worst performing assets that are now OH to UG. Upon receipt of the typical feeder database of information – our analysis turned primarily to the results of that analysis. Therefore, the conclusions relative to overall system improvement from an undergrounding policy adoption are driven by the comparisons made using the ten typical feeders as that analysis is more reflective of the system as a whole. The WPF analysis may be useful in identifying the prioritization of investment should an underground policy be developed – for example, Exhibits 39 and 41 provide summary statistics for each of the 15 feeders.

Identification Process

Pepco annually categorizes all 750 District OH and UG feeders that experienced outages during the reporting year (the 2008 reporting year is October 1, 2007 – September 30, 2008) using their unique Composite Performance Index (CPI) process. The CPI takes into account several variables to rank the feeders including the total number of interruptions on the feeder, the total customer hours of interruption, the number of customers affected, and also system averages for the interruption frequency (SAIFI) and the average interruption duration (SAIDI) for the reporting year.

The CPI calculation results in the feeders being ranked from worst performing up to those that experience no interruptions. This list is than carefully reviewed to determine which of the CPI ranked feeders are actually to be selected as the 15 worst performing feeders (WPF) based on the requirement to identify 2% of the feeders as WPFs. This secondary ranking process is based on considerations such as not reselecting previously identified feeders that are still undergoing improvement work until the upgrades are completed, and such as the outage data is reviewed for potential distorting items such as large numbers of very small outages (1-10 customer effected) or long outages (for example a large tree taking out a small number of customers for a long period as poles were broken and the tree must be cleared).

Based on the straight mathematics, the filtering rules, and the data integrity checks, the 15 WPFs are selected and submitted to the Commission in Pepco's Annual Consolidated Report. The 2008 Report's 15 WPFs are used for this analysis.

Analysis of Worst Performing Feeder Statistics

Four of the 15 feeders were 100% UG and the other 11 feeders were a combination of OH and UG – there were no 100% OH service feeders in the 2008 WPF. Exhibit 38 shows the feeders by circuit number, the miles of conductor, and the breakdown of the assets into OH or UG facilities.

Exhibit 38 Summary Statistics for Worst Performing Feeders based on CPI, 2008 Reporting Year

WPF ID	SAIFI	CAIDI	SAIDI	Circuit-Miles OH	Circuit-Miles UG	Percentage Lines OH	Percentage Lines UG
27	5.04	346	1,743	0	3.21	0%	100%
53	3.88	556	2,153	0	2.57	0%	100%
84	5.96	497	2,960	0	1.61	0%	100%
14015	3.75	98	367	7.83	1.09	88%	12%
14200	4.96	100	495	2.53	.37	87%	13%
14703	7.07	229	1,618	6.19	.91	88%	12%
14727	5.48	102	557	10.61	1.59	87%	13%
14753	5.19	199	1,035	4.16	1	81%	19%
14768	2.14	291	623	8.63	2.82	75%	25%
14900	5.05	108	547	10.61	4.29	71%	29%
15009	4.31	147	633	7.36	.26	97%	3%
15014	4.08	98	400	6.53	.55	92%	8%
15705	7.66	179	1,371	9.13	2.69	77%	23%
15706	4.99	68	338	6.7	1.84	78%	22%
15986	6.56	364	2,384	0	1.73	0%	100%
				80.3 miles	**26.4 miles**	**75%**	**25%**

Pepco supplied the number of outages for these 15 feeders which is summarized in Exhibit 39.

Exhibit 39 Worst Performing Feeders, Number of Outages by Asset

Outages	Primary	Secondary	Unknown	Total
OH	191	56	28	275
UG	52	21	7	80
URD	7	7	0	14
Unknown	11	0	0	11
Total	261	84	35	380

Due to the quality of the outage data supplied by Pepco approximately 10% of the outages had little useable data associated with the outage. This lack of information was in two major categories – identification of the distribution construction in the area: OH, UG, or URD and whether the outage was a primary or secondary event. In all cases the outage information on customers and duration was included.

Not satisfied with 46 unknowns out of 380 incidents (>10% error), the Shaw Consultants team further researched the outage reports supplied by Pepco and the outage locations using Google Earth for virtual field visits to try to identify the most likely construction in the area and used the number of customers involved to determine, with a high level of confidence, whether the outages were in the primary or secondary portion of the distribution system. The outages were broken down according to the three major types of construction; overhead (OH), traditional underground (UG) and underground residential distribution (URD) and then into whether the fault involved the primary conductors and equipment or the secondary conductors or equipment. The summary of this revised data is provided in Exhibit 40.

Exhibit 40 WPF Outages by Asset, CPI, 2008 Reporting Year

Outages	Primary	Secondary	Grand Total
OH	220	66	286
UG	54	26	80
URD	7	7	14
Total	**281**	**99**	**380**

Based on this information we developed the incidents per mile of OH and UG construction as depicted in Exhibit 41.

Exhibit 41 WPF Summary Statistics with Added Detail, CPI, 2008 Reporting Year

WPF	SAIFI	CAIDI	SAIDI	Incidents OH	Incidents UG	Incidents/Mile OH	Incidents/Mile UG
27	5.04	346	1,743	0	16	0	5
53	3.88	556	2,153	0	12	0	4.7
84	5.96	497	2,960	0	17	0	10.6
14015	3.75	98	367	35	2	4.5	1.8
14200	4.96	100	495	7	7	2.8	18.9
14703	7.07	229	1,618	36	4	5.8	4.9
14727	5.48	102	557	24	2	2.3	1.3
14753	5.19	199	1,035	23	5	5.5	5
14768	2.14	291	623	22	1	2.5	0.4
14900	5.05	108	547	24	1	2.3	0.2
15009	4.31	147	633	24	0	3.3	0
15014	4.08	98	400	21	1	3.2	1.8
15705	7.66	179	1,371	43	3	4.7	1.1
15706	4.99	68	338	27	4	4	2.2
15986	6.56	364	2,384	0	19	0	11
				286	**94**	**3.6**	**3.6**

The WPFs have a remarkably close statistic in the number of incidents per mile when *all the primary and secondary incidents for both the Pepco OH and UG distribution assets are included* – 3.6 incidents per mile for the 2008 reporting year.

The incidents per mile of OH and UG for both Primary and Secondary are used to estimate the potential improvement of placing assets that are now OH to UG for the 15 WPF. For the 2008 WPFs the incidents per circuit-mile was shown to be 3.6 incidents per mile for both the OH and UG portions when all outages are included for the 15 WPFs. However when the weather, number of customers involved, and duration of the outages are analyzed a different picture develops. As the study is a review of placing OH assets UG at this point we will combine the UG and URD incidents into a common category to avoid confusion – there is either OH or UG construction. Separating the data for outages into the assets involved - primary or secondary, and the weather conditions - storm or non-storm, resulted in the statistics presented in Exhibit 42.

Exhibit 42 Fifteen Worst Performing Feeders OH vs. UG Outages, 2008 Reporting Year

Outages	Non-Storm Primary	Storm Outages Primary	Non-Storm Secondary	Storm Outages Secondary
OH	201	19	62	4
UG	59	2	32	1
Total	260	21	94	5

Using the circuit miles developed for the 15 WPFs, these results are translated into incidents per circuit-mile. It is important to note that the secondary for both OH and UG was estimated at the same length in circuit miles as the primary. Exhibit 43 summarizes the incidents per circuit mile.

Exhibit 43 Fifteen Worst Performing Feeders Incidents per Circuit Mile, 2008 Reporting Year

Outages	All Outages	Primary	Secondary	Non-Storm	Storm
OH	3.6	2.7	0.8	3.3	0.3
UG	3.6	2.3	1.2	3.4	0.1

The performance of the 15 WPFs on an incident per circuit-mile bases is nearly equal; however, the UG primary was slightly more reliable while the UG secondary was 50% less reliable. Relative to the storm outages, UG had 1/3 the OH incidents on a per circuit-mile basis. Storm incidents on the WPFs in the 2008 Reporting Year were approximately 8% of the OH incidents and 3% of the UG incidents per circuit-mile.

Investigating the number of customers affected by the OH, UG, primary, and secondary during storms and non-storm conditions resulted in the statistics provided in Exhibit 44, indicating that storm outages were of longer duration than non-storm outages for the WPFs.

Exhibit 44 WPFs, Total Customers Affected by Outages, Storm and Non-Storm, 2008 Reporting Year

Fifteen WPF	Non-Storm Outages	Storm Outages
Customers	84,725	6,308
Hours	231,687	41,164
Hours per Customer	2.7	6.5

Breaking out the affected customers into OH and UG primary and the secondary incidents, the results are provided in Exhibit 45.

Exhibit 45 WPFs, Customers Affected by Asset, Storm and Non-Storm, 2008 Reporting Year

WPF	Non-Storm Primary	Storm Outages Primary	Non-Storm Secondary	Storm Outages Secondary
OH	65,289	5,556	242	4
UG	18,586	747	608	1
Total	83,875	6,303	850	5

Finally the results of the outages were developed for both OH and UG as documented in Exhibit 46 and 47.

Exhibit 46 WPFs, Total OH Customers Affected by Outages, Storm and Non-Storm, 2008 Reporting Year

WPF	Non-Storm Outages	Storm Outages
Number of Customers	65,531	5,560
Hours	139,805	37,321
Hours per Customer	2.1	6.7

Exhibit 47 WPFs, Total UG Customers Affected by Outages, Storm and Non-Storm, 2008 Reporting Year

WPF	Non-Storm Outages	Storm Outages
Number of Customers	19,194	748
Hours	91,882	3,843
Hours per Customer	4.79	5.14

4.1.7 Comparison of Findings – 10 Typical Feeders Versus 15 WPF

In this section we compare the results of the typical and worst performing feeder analysis completed in the previous two Sections of this report. Our conclusions relative to the information are that the typical feeders are a better indicator of the system performance improvement that might be realized from undergrounding, while the worst performing information may provide an approach to prioritization of investment should undergrounding be adopted.

Incidents per Mile

The 2008 15 WPFs are comprised of 106.7 miles of which 75% is overhead construction. The WPFs with OH lines (11 of the 15) have an average of 7.3 circuit miles of OH lines – this is approximately 73% greater than the 10 typical feeders selected as average performers for the 2008 Reporting Year, which have 4.2 circuit miles of OH lines per feeder. The correlation between incidents and circuit miles of exposure is a key factor in the reliability measurement of the feeders. Customers are affected by incidents – some will experience a sustained outage while others, if the feeder breaker or line recloser operates while a fuse is cleared, will experience a momentary outage. The more incidents the higher the SAIFI is for the customers on the feeder.

The Exhibits in this Section of the report compare the 10 typical feeders to the 2008 Reporting Year 15 WPF sin several performance categories of incidents per mile summarized by OH and UG primary and secondary assets.

OH Primary

Comparing the OH primary of the two categories (10 Typical and 15 WPFs) indicates that the WPF's had 220 primary incidents in the 2008 Reporting Year and the typical feeders had 343 primary incidents in the five-year period for a yearly average of 69 incidents. Exhibit 48 shows the breakdown and documents that the WPFs in the 2008 Reporting Year were experiencing an additional 0.7 incidents per circuit-mile overall.

Annual performance of feeders, particularly OH feeders will vary from year to year based on local energy bursts, tree trimming schedules, construction work in areas, and other factors. As expected, the 15 WPF overhead sections performed worse on an incidents per circuit-mile basis than the typical feeders.

Exhibit 48 Comparison of Typical and WPF, Incidents per Circuit-Mile, Overhead Primary

Category	Incidents	Circuit Miles Analyzed	Incidents per Circuit-Mile (Non-Storm)	Incidents per Circuit-Mile (Storm)	Incidents per Circuit-Mile (Combined)
15 WPF	220 in 12 months	80.3	2.50	0.24	2.74
10 Average for 60 Months	69 average of 343 incidents	33.4	1.74	0.32	2.06

UG Primary

Underground primary performed worse on the WPFs, with an incident per circuit-mile 3 times that of the 10 typical feeders – see Exhibit 49. It should be noted that UG construction goes through a lifecycle of performance and after 30 – 35 years the probability of failure for cables and splices used to connect sections of cable increases dramatically as the assets approach their end of life. Also, general utility UG practice is to repair a cable several times before determining that the cable is beyond repair and needs to be replaced. While UG assets will help in the immediate future with outages, many outage issues will occur as the UG assets approach their end of life. In an UG study such as this, the quantity of the OH assets requiring underground construction to relocate them will require decades to complete. By such time the early projects will be experiencing cable and joint failures.

Exhibit 49 Comparison of Typical and WPF, Incidents per Circuit-Mile, Underground Primary

Category	Incidents	Circuit-Miles Analyzed	Incidents per Circuit-Mile (Non-Storm)	Incidents per Circuit-Mile (Storm)	Incidents per Circuit-Mile (Combined)
15 WPF	61 in 12 months	26.4	2.2	0.1	2.31
10 Average for 60 Months	14.6 average	20.2	0.72	0	0.72

OH Secondary

Secondary outages occur in the OH systems at nearly the same rate in a comparison of WPFs with the typical feeder performance as shown in Exhibit 50. These incidents generally involve very few customers and have little effect on total reliability numbers. Over the 5-year period the 10 typical feeders experienced more secondary OH incidents per circuit-mile than the 2008 Reporting Year WPFs.

Exhibit 50 Comparison of Typical and WPF, Incidents per Circuit-Mile, Overhead Secondary

Category	Incidents	Circuit-Miles Analyzed	Incidents per Circuit-Mile (Non-Storm)	Incidents per Circuit-Mile (Storm)	Incidents per Circuit-Mile (Combined)
15 WPF	66 in 12 months	80.3 miles	0.77	0.05	0.82
10 Average for 60 Months	28 average of 142 incidents	33.4	0.80	0.05	0.87

UG Secondary

Secondary outages also occur in the UG systems at nearly the same rate when comparing the WPFs with the typical feeders. These incidents generally involve very few customers and have little effect on total reliability numbers. Again we note that the UG failures due to cable aging, inadvertent dig-ins and other causes are higher across the 15 WPFs and 10 typical feeders. See Exhibit 51.

Exhibit 51 Comparison of Typical and WPF, Incidents per Circuit-Mile, Underground Secondary

Category	Incidents	Circuit-Miles Analyzed	Incidents per Circuit-Mile (Non-Storm)	Incidents per Circuit-Mile (Storm)	Incidents per Circuit-Mile (Combined)
15 WPF	33 incidents in 12 months	26.4	1.21	0.04	1.25
10 Average for 60 Months	14 average of 70 incidents	20.2	0.68	0.01	0.69

CAIDI

The second major aspect of outages is its duration, or CAIDI, which is the Customer Average Interruption Duration Index. This statistic is obtained by capturing the total minutes of each interruption divided by the total number of customers interrupted. This is a more significant performance index number than SAIDI, which is the System Average Interruption Duration Index. SAIDI is calculated using the total interruption minutes divided by all the customers served by a utility, not simply those affected by the actual outages, and as a result portrays a different story.

OH primary

The 10 typical feeders' outage incidents were shorter in duration in 2008 as compared to 2004. It appears that Pepco is improving restoration on the typical feeders selected. In fact, the CAIDI for OH primary incidents on the 15 WPFs was 40 minutes less per outage than the 5 year average on the 10 typical feeders during non-storm periods and 54 minutes less during storms. This is a very noticeable improvement. A comparison of the CAIDI information for overhead primary is provided in Exhibit 52.

Exhibit 52 Comparison of Typical and WPF, CAIDI, Overhead Primary

Category	Customers Affected	Outage Hours	CAIDI (Non-Storm)	Customers Affected	Outage Hours	CAIDI (Storm)
15 WPF	65,289	137,569	2.11 hrs	5,556	37,165	6.69 hrs
10 Average for 60 Months	8,573	23,704	2.76 hrs	2,814	21,390	7.60 hrs

UG Primary

UG primary on the 15 WPF experienced longer outages than the typical feeders, by 39 minutes on average.

Exhibit 53 Comparison of Typical and WPF, CAIDI, Underground Primary

Category	Customers Affected	Outage Hours	CAIDI (Non-Storm)	Customers Affected	Outage Hours	CAIDI (Storm)
15 WPF	18,586	89,096	4.79	747	3,843	5.14
10 Average for 60 Months	1,982	8,653	4.37	0	0	0

OH Secondary

OH secondary, unlike OH primary has not improved and it required twice as long to restore secondary on the 15 WPFs. During storms, while secondary is the last portion of the restoration effort, only 4 customers were affected on all 15 feeders and it took nearly 40 hours to restore their service. Exhibit 54 summarizes the CAIDI information for the overhead secondary customers.

Exhibit 54 Comparison of Typical and WPF, CAIDI, Overhead Secondary

Category	Customers Affected	Outage Hours	CAIDI (Non-Storm)	Customers Affected	Outage Hours	CAIDI (Storm)
15 WPF	242	2236	9.24	4	156 hrs	38.9 hrs
10 Average for 60 Months	52	253	4.90	13	50	3.87

UG Secondary

Restoration of UG secondary for the 15WPF is 52 minutes better than the 5 year average for the typical feeders; this information is summarized in Exhibit 55.

Exhibit 55 Comparison of Typical and WPF, CAIDI, Underground Secondary

Category	Customers Affected	Outage Hours	CAIDI (Non-Storm)	Customers Affected	Outage Hours	CAIDI (Storm)
15 WPF	608	2,786	4.6 hrs	1	0.168	0.17 hrs
10 Average for 60 Months	45	243	5.5 hrs	0.2	0.57	2.8 hrs

4.2 Summary of Pepco Reliability Programs

Reliability of the electrical distribution system, either in a network or in a radial configuration, is a function of business processes, engineering design criteria and use of available supporting systems and data. Shaw Consultants reviewed Pepco's existing programs to assess their effect on the present reliability performance of both the overhead and underground systems.

4.2.1 Outage reporting and analysis

Pepco uses an Outage Management System (OMS) supplied by Configured Energy Systems (CES), a popular system in use at many electric utilities. The CES system uses algorithms to group reported outages by location and connectivity, thereby allowing it to predict the location of the electrical fault or isolating device which is causing the outage. The connectivity model and customers' locations are supplied from Pepco's Geographic Information System (GIS).

The OMS allows field personnel to report the cause of the outage, repairs made, equipment failures, and other relevant information using a Mobile Dispatch System. While the technology plan is well thought out and functional, there is latitude in reporting the causes and repairs made for each outage. This latitude can result in varied reporting among field staff that makes consistent data and trending analysis difficult and may contribute to future outages if trends cannot be identified. Specifically, drop-down selection screens[7] for use by the repair crews in the field allow the crews to identify and clarify outage information and causes but in the field there is inconsistent use of the reported information. This makes it difficult to determine why the failure occurred and may impact the ability to identify common problems to avoid future outages.

In order to compare and contrast the implications of undergrounding overhead assets, Shaw Consultants needed to identify the outages as being either underground or overhead. Shaw Consultants experienced some difficulty analyzing the outage history reports, because many did not identify whether the failure on combined overhead and underground feeders had occurred in overhead or underground equipment. Consequently, we found it necessary to translate the Maryland grid system (still used by Pepco to identify outage locations) into latitude and longitude by location, so that we could use Google Street View to "virtually visit" each location to examine the nature of the assets. This allowed our team to clarify and provide more specificity for many of the outages in the five-year history.

It should be noted that during our review of the five-year history of the ten average feeders, discussed below, we discovered that the reporting has improved between 2004 and 2008. New drop down selection screens have been implemented, but further training and verification is recommended to improve the accuracy of the information. Shaw Consultants believes that one key to long term improvement in feeder performance is to continue standardizing the information coming from the repair crews; this will enable timely analysis and action by reliability-focused engineering staff.

4.2.2 Pepco Design Standards

The current Pepco engineering design standards do not specifically recommend the undergrounding of existing overhead feeders for any reliability issues. Overhead lines being upgraded are typically replaced with overhead lines, and feeder additions in overhead areas are typically built according to the prevailing design. The current standard for overhead construction improvement in most areas is to use covered wire, also known as "tree wire," which is able to withstand a brush-by or small limb on the

[7] For example, we saw a case where the cause was "deterioration," the equipment type was "NA," the device type was "primary bare wire", and the device was "NA."

wires without a circuit or fuse operation. Tree wire is not able to withstand constant rubbing against a tree, as its insulation will wear off, causing a short between phases in the cable or a connection to ground, resulting in an outage. There are currently no design criteria or programs planned to place overhead assets underground during system upgrades.

4.2.3 Overhead Reliability Improvement Programs

While this study was commissioned to focus on the cost and benefits of undergrounding of existing overhead assets, Pepco reported to Shaw Consultants that they had initiated several reliability-focused overhead changes to their design standards, based strictly on the desire to improve reliability, which are summarized in the Sections below. Pepco indicated that additional funding has been allocated specifically for that purpose.

Overhead Programs Presently Implemented

The following programs, focused on system reliability, were reported to be in place at Pepco:

- Tree wire, which is typically used to prevent outages caused by momentary contact with tree branches, is being installed and used in all overhead areas when new wires are run through treed areas.
- Lightning arrestors are being replaced and added to better handle line surges from lightning strikes.
- Animal guards are being added, where possible, to prevent outages caused by animals coming in contact with and grounding equipment.

Trial Overhead Programs

Pepco indicated that it plans to implement the following trials or pilot programs for specific areas to assess their contribution to improving reliability:

- Overhead bundled (aerial) cable, which is fully insulated, will be used on a test basis in heavily treed areas, replacing open wire cross arm construction as the main line conductor. Under the planned construction, this mainline will stay live under most weather conditions, with outages confined, if they happen, to the various lines tapping the bundled cable. Aerial cable greatly increases reliability in overhead areas by eliminating many tree related incidents.
- In heavily treed areas, Pepco is considering a "go-around" policy, which may include relocation of poles to the opposite side of the street using construction such as aerial spacer cable.
- Aerial spacer cable, also known as Hendrix cable, will be tested on a limited basis in heavily treed areas, as it can be more easily routed around problem areas and can withstand brush-by contacts. The cable is supported by a steel messenger; should a large tree fall on the aerial cable it generally detaches several sections of primary off the poles before the steel messenger will break.
- Using Internet-controlled switches, Pepco has started a program to identify and isolate faults, allowing it to restore power to the majority of customers using a "drop and pick" philosophy of switch operations. This will not eliminate outage incidents, but will reduce the outage duration. Partial restoration of less than five minutes, in many cases, will be attainable.
- Pepco is involved in a pilot program using fault indicators to assist first responders in locating outages quicker. This has great potential in heavily treed areas where it can be difficult to see

failures within trees at night and during storms. Again, this should have a significant effect, if successful, on overhead restoration times.

4.2.4 Underground Reliability Improvement Programs

Pepco indicated that it is also focusing on reliability improvement programs for its underground systems, which are more targeted to outage duration than the number of incidents. Pepco indicated that the goal when an outage occurs is to locate the fault and isolate as many customers from the fault as possible, allowing partial restoration and a reduction in CAIDI.

Underground Programs Presently Implemented

In evaluating the benefits and costs of undergrounding the assets, it is necessary to understand the long-term changes likely to occur in the performance of underground assets. Similar to overhead, Pepco indicated that its design criteria are being enhanced to better address reliability within construction standards. These changes are expected by Pepco to reduce the outages for underground customers that can be isolated from the actual faults. The new underground facilities that are being built (15 kV class upgrades) are, according to Pepco, being designed with sufficient ties (to other sources of power and other feeders) to allow for rapid restoration of most customers.

Underground Trial Program

Pepco also relayed to Shaw Consultants staff that it is presently involved in a pilot program using fault indicators to assist first responders to locate outages quicker. This has great potential in the underground system if the fault indicators can be seen from the surface, without entering manholes. Both switching and crew assignments could then be facilitated without a search for the fault prior to restoration efforts. If this is successful, and with the 15 kV class upgrades allowing partial restoration of the feeders, this could have significant impact on outage duration on those feeders with fault indicators and circuit ties.

4.2.5 Tree Maintenance

Pepco’s tree program is based on a two-year maintenance cycle. Tree maintenance must comply with ordinances and agencies that are concerned with maintenance of trees. While there is little debate that the trees are magnificent, they are also a leading contributor to the number of incidents in the areas they share with Pepco overhead primary.

Shaw Consultants visited heavily treed areas in Worst Performing Feeder overhead areas. Pepco provided our team with a company forester, who showed us issues with the trees, including tree interference with lines, failed trees that have recently been removed, and recent replacement plantings by the Urban Forestry Administration. It was clear that trees are contributors to reduced system reliability, but it is also clear why residents wish to maintain their tree umbrella. The major tree issues in the District are the large oak species of trees planted in the late 1930’s. Many of the trees are dying due to natural end-of-life; as this occurs, the service reliability in this area should improve.

The trees are maintained by the Urban Forestry Administration, which selects replacement trees that promise quick growth, ample shade, and provide ground water control. In the past, there was not a specific effort made to select specimens that would limit future interference with overhead lines. In short, failed trees were being replaced with trees that were not suitable for placement under electric distribution lines; these replacement trees were causing outages only 3-5 years after planting. Many utilities work with their customers and local tree wardens/agencies to select mutually acceptable trees that provide shade and beauty but reduce the potential for multiple electrical outages, and Pepco in recent years has been planting suitable low growth trees underneath power lines.

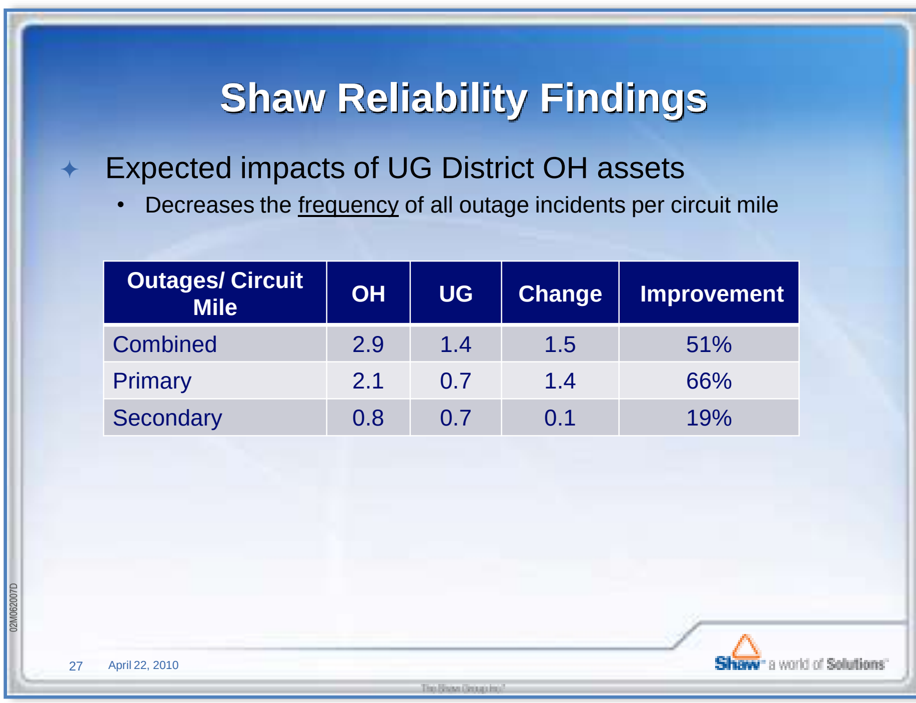
4.3 Discussion of Findings

The reliability data developed using typical feeders allow us to project that based on a five-year average, the total undergrounding of the present overhead primary, mainlines and laterals, will result in a decrease of 1.4[8] primary outage events per mile for the sections and areas where overhead primary is replaced by underground primary. For the 15 WPFs the result would be an additional 0.7 incidents per circuit-mile improvement or 2.1 incidents per circuit-mile when compared with the average underground primary events. Exhibit 56 demonstrate the anticipated improvement for the system based on the average or typical feeders – a 52% improvement overall for the District.

Similarly CAIDI, or duration, for primary incidents would increase approximately 1.6 hours based on historical data over an average 5 year period, with an average UG primary restoration time (CAIDI) in the range of 4.4 hours per event. See Exhibit 57 which demonstrates the primary outage durations would increase by 58% while secondary would increase by 11% as a result of a move to undergrounding.

For the Pepco District system, with an estimated 660 circuit miles of overhead primary, the total number of interruptions would decrease by 924 events, with and without storms. In the 2008 Reporting Year, Pepco reported a total of 1,753 total outage events for OH and UG, including primary and secondary. These 924 events represent more than half of the events and the majority of the customer outages.

Exhibit 56 Reliability Conclusion Summary, Improvement in Number of Incidents



Outages/ Circuit Mile	OH	UG	Change	Improvement
Combined	2.9	1.4	1.5	51%
Primary	2.1	0.7	1.4	66%
Secondary	0.8	0.7	0.1	19%

[8] Based on the 10 typical feeders analyzed for 5 years: overhead primary had 2.1 incidents per circuit-mile including storm and non-storm events, while underground primary had 0.7 incidents per circuit-mile. This was for radial feeders only and did not include the Pepco DC network areas.

Exhibit 57 Reliability Conclusion Summary, CAIDI Implications

Shaw Reliability Findings

- Outage Durations (CAIDI)
  - Increases the duration of non-storm outages (CAIDI) by 1.6 hours or 96 minutes, or 58% per incident

	OH	UG	Change	% Increase
Primary	2.8	4.4	1.6	58%
Secondary	4.9	5.4	0.6	11%

- Consistent with industry experience this analysis indicates fewer outages with longer durations would be expected
- These CAIDI values do not reflect any potential improvements due to adoption of Smart Grid technologies

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5 Evaluation of Pepco's Cost to Underground

When considering replacement of overhead distribution system with an underground system, key considerations include the cost to perform the work, and the effect it will have on both reliability and electric rates for Pepco customers over the next several years. In Section 4 of this report we considered the reliability implications of an underground electrical system. In this section we evaluate and compare a 2006 undergrounding cost estimate developed by Pepco in response to the District Public Service Commissions' investigation pursuant to Formal Case No. 1026 & 766. The Pepco estimate is compared to industry construction cost norms as documented by RS Means Cost Estimating Guide. RS Means is a division of Reed Business Information that provides cost information to the construction industry so contractors in the industry can provide accurate estimates and projections for their project costs. It has become a data standard for government work in terms of pricing, and is widely used by the construction industry as a whole. Cost information is updated annually.

Pepco initially developed a high level estimate of the cost to place assets underground in a 2004 study, which was subsequently expanded into a more detailed analysis in 2006. While the 2004 study was a magnitude of order cost estimate, the 2006 study was extremely detailed and required significant resources to develop. Pepco stated that the effort *"includes 1254 hours of Company employee time and 788 hours of contract support labor involved directly in the estimate and which amounted to approximately $186,000, and a significant number of untracked labor hours associated with report preparation and review, and executive involvement."*

Both the 2004 and 2006 Pepco cost estimating methodologies utilized industry standard engineering approaches albeit at different levels of detail. In the 2006 cost estimate Pepco selected a single feeder for detailed analysis and using a combination of field surveys, design options, plan development and the use of Pepco's work order management information system (WMIS), a work plan was developed and the construction costs were estimated. The costs were based on actual Pepco construction experience using the data captured by the WMIS in the normal course of business. In addition, for areas where the Pepco WMIS would not have accurate information, such as the cost for an electrician to convert a customer's service entrance from overhead to underground, electricians were hired to estimate both residential and commercial service entrance conversion costs.

Feeder 14007 was selected for underground conversion analysis by Pepco as representative of the District service territory. This feeder is fed from Station 133 which is located at the junction of 12th and Irving Streets. It consists of both overhead and underground construction; 93% or 9.3 circuit-miles are overhead and 7% or 0.7 circuit-miles are underground.

Exhibit 1 details the cost estimated to convert Feeder 14007 to totally underground. The costs are provided on both a dollar cost, unit cost and percentage of total cost basis, all in 2006 dollars. Costs are broken down by major material and construction elements as follows: primary mainline, transformers, secondary mainline, service, street lights, permitting, and removal costs. On a percentage basis, secondary mainline conversion is the largest cost at 36% followed by primary mainline at 30%, services at 20%, transformers at 10%, street light at 3%, removal cost at 0.8% and District permitting cost at 0.4%.

Exhibit 58 Pepco 2006 Estimate to Underground Feeder 14007

Item	Cost	Unit cost	Percentage of Total Project Cost
Primary Mainline			
Conduit and Cable	$ 29,806,689	$ 3.2 million/mile	
Splice and Manhole	$ 2,009,892	$ 0.2 million/mile	
Switch Manholes	$ 459,453	$0 .05 million/mile	
Primary Mainline Subtotal	**$ 32,276,034**	**$ 3.5 million/mile**	**30%**
Transformers	$ 10,881,955	$ 1.2 million/mile	10%
Secondary Mainline	$ 39,065,680	$ 24,000/customer	36%
Service - Commercial			1%
Utility Cost	$ 393,158	$ 7,000/customer	
Customer Cost	$ 877,785	$ 16,000/customer	
Service - Residential			19%
Utility Cost	$ 16,962,231	$ 11,000/customer	
Customer Cost	$ 3,502,354	$ 2,000/customer	
Street Light Cost	$ 2,928,875	$ 0.03 million/mile	3%
District Permit Cost	$ 403,572	% of total project cost	0.4%
Removal Cost	$ 818,944	% of total project cost	0.8%
Total	**$108,110,569**		

The scope of the current project limits the detailed cost estimating that can be created or validated. However, the outage data discussed previously in Section 5 of this report documented that the major gains in reliability would result from undergrounding the primary mainline conductors only. Based on this information, Shaw Consultants focused on analyzing the Pepco cost estimate associated with the undergrounding of the mainline primary alone.[9]

5.1 RS Means Comparison

To compare Pepco's 2006 cost estimate for undergrounding the primary mainline of Feeder 14007, Shaw Consultants developed a cost estimate using the RS Means construction cost database. RS Means is a cost database for heavy construction; it includes common construction components such as trenching, conduit, concrete, cable and manholes. It does not include specialized items such as switches or splicing of cable. The Shaw Consultants' cost estimate is based on the RS Means costs for materials, equipment and labor hours and includes an allowable markup for overhead. The costs are further adjusted by locality in order to account for local differences in prevailing wage rates and material costs.

For this analysis Shaw Consultants used material quantities provided by Pepco to develop the cost estimate, based on the primary schematic plan for Feeder 14007 as utilized for the 2006 estimate. Shaw Consultants also relied on information from Pepco's work management information system, which provided a reference for typical material sizes and quantities used on the Pepco system.

The cost estimate is developed for underground cable, conduit, manholes, labor productivity, indirect and miscellaneous project costs.

[9] Pepco uses the term "mainline line primary" to include 3-phase mainline as well as 1, 2, and 3 phase laterals.

5.1.1 Underground Cable Cost

The cost of underground cable was estimated using the lengths provided by Pepco for feeder 14007. Feeder 14007 overhead lines are divided into two distinct types of construction: 3 phase mainline and laterals, and single phase laterals. Exhibit 59 outlines the circuit-miles of overhead line for each construction type which represents 9.28 circuit-miles in total.

Exhibit 59 Circuit-miles of Overhead Line – Feeder 14007

3-Phase Mainline	3-Phase Laterals	1-Phase Laterals	Total
4.25	0.89	4.14	9.28

Design details referenced in the 2004 Pepco undergrounding cost estimate were used to develop the Shaw Consultants estimate for the cost of underground cable. The 2004 Pepco estimate described a one for one replacement of overhead mainline with underground cable, using 600 kcmil, 13 kV, 3-conductor cables. This specific cable was not available in the RS Means database. The closest cable specification for which a cost was available was a 15 kV, 500 kcmil, 3 conductor cable. This cable is very similar in specification to that preferred by Pepco.

The primary mainline, at a length of 4.25 circuit-miles, was assumed replaced with 15 kV, 500 kcmil, 3-conductor cable for the Shaw Consultants estimate. The 3-phase lateral, at a length of 0.89 miles, was estimated using 15 kV, 1/0, 3-conductor cable as a replacement. The single phase overhead lateral, at a length of 4.14 miles, was doubled to provide for an underground loop design as described in the 2004 Pepco cost estimate. This doubled the miles of underground cable to 8.28 miles. The loop design is typical for the primary system for an underground residential distribution circuit. The loop system is typically installed in conduit with a normally open point at or near the midpoint of the loop. The open point in the loop can be closed in the event of a cable failure to allow service to be restored in a timely manner. The intent of a loop designed underground system is to reduce exposure to the underground cables and to provide for contingencies in the event of a failure. The looped distribution system design also avoids some exceptionally long restoration times for faults occurring on the underground distribution system. Because RS Means did not offer a single conductor version of the 15 kV, 1/0 cable, the cost of a 3 conductor 15 kV, 1/0 cable was used and divided by 3 to approximate the cost of a single conductor cable[10].

Exhibit 60 details the circuit-miles and the material, installation and overheads costs as provided in the RS Means database for each of cables previously discussed.

Exhibit 60 Cable Cost Breakdown

	Circuit-Miles	Material	Installation	Overheads	Total
500 kcmil, 15 kV, 3-conductor	4.25	$1,133,220	$125,664	$177,276	$1,436,160
1/0, 15 kV, 3-conductor	.89	$85,305	$15,792	$16,403	$117,500
1/0, 15 kV, 1-conductor	8.28	$264,496	$48,965	$50,859	$364,320
Total		**$1,483,021**	**$190,421**	**$244,538**	**$1,917,980**

[10] Costs may be underestimated due to economies of scale associated with producing a 3 conductor cable.

5.1.2 Conduit Costs

The major components of conduit construction are trenching, duct bank, concrete encasement, and roadway paving. The cost estimate for each of these elements was based on Pepco design requirements and is detailed as follows:

- A 4x4 foot trench was assumed and a cost determined based on the 9.28 miles of trench required. In addition, in order to account for the significant hand digging that would be required around trees to protect their root system, 50% was added to the cost of trenching as an approximation based on discussions with Pepco.
- The duct bank cost estimate was based on a PVC conduit in a configuration of 4 pipes wide by 2 pipes high.
- The cost of encasing the pipes in concrete was calculated based on the concrete material and the placement or pouring of the concrete, both in cubic yards.
- Roadway paving estimate includes both temporary and permanent repaving of roadways in the estimate. RS Means provides costs for various paving thickness and road width. Dimensions used for temporary paving were 2½ inches thick and 20 feet wide, while permanent paving was 4 inches thick and 30 feet wide (estimated road width). There is a requirement in the District that the entire road width be repaved when a trench is longer than 30 feet.

Exhibit 61 provides a summary of the conduit construction costs detailed above.

Exhibit 61 Conduit Cost Breakdown

	Material	Installation	Total
Excavate trench	NA	$583,081	$583,081
Hand digging	NA	$399,245	$617,015
Duct bank	$463,035	$610,030	$1,420,954
Concrete	$875,602	NA	$962,200
Place concrete	NA	$114,598	$175,120
Temporary Roadways, bituminous concrete paving, 2-1/2" thick, 20' wide	$2,204,928	$2,376,422	$4,581,350
Permanent Roadways, bituminous concrete paving, 4" thick, 30' wide	$3,356,390	$2,694,912	$6,051,302
Total	**$6,899,955**	**$ 6,774,825**	**$14,391,023**

5.1.3 Manholes

Quantities for manholes were taken directly from the schematic plan for Feeder 14007, and included 3 switch manholes and 107 tap holes. Switch manholes as the name implies are those which are used to house isolating switches which are an integral part of maintenance and operation of an underground system. Tap manholes are used to facilitate individual customer service attachments or taps. There were no splice manholes displayed in the schematic plan, but 100 splice manholes were listed in the Pepco design sheets, therefore a quantity of 100 was included in the Shaw Consultants estimate.

Exhibit 62 details the number of manholes and the material and installation costs as provided in the RS Means database for each manhole type previously discussed.

Exhibit 62 Manhole Cost Breakdown

	Quantity	Material	Installation	Total
Switch manholes	3	$11,850	$10,050	$21,900
Splice manholes	100	$395,000	$335,000	$730,000
Tap manholes	107	$136,425	$107,000	$243,425
Total		**$543,275**	**$452,050**	**$995,325**

5.1.4 Labor Productivity

The District of Columbia has restricted work hours for rush hour roads, which only allow construction between 9:30am and 3:30pm. Because RS Means uses an 8 hour workday in its calculations, Shaw Consultants added 25% to labor costs overall to account for decreased productivity due to reduced working hours, from 8 to 6 hours per day. Allowing for setup and takedown time, Shaw Consultants estimated that these restrictions would reduce daily output by approximately 25%. This productivity adjustment is reflected in Exhibit 63.

Exhibit 63 Labor Productivity Adjustment

Total Labor Cost	Lost Productivity Adder (25%)	Labor Cost Including Productivity Adder
$7,417,295	$1,854,324	$9,271,619

5.1.5 Indirect & Miscellaneous Project Costs

In addition to the direct costs addressed in the preceding discussion there are also a number of indirect and miscellaneous costs which must be accounted for in order to get a complete picture of the total costs associated with a construction project. These include engineering, permitting, removal, project management, overhead and contingency costs. RS Means provides a range of national averages for these costs, as a percentage of the total direct project cost as follows.

- Engineering costs for design of the underground system are provided in RS Means in the range of 4.1% to 10.1%. For this estimate Shaw Consultants assumed the midpoint of this range, 7.1%.
- Permitting costs range from 0.5% to 2% of a total project's cost in RS Means. Pepco used 0.4% for permit costs in their 2006 estimate, in line with low end of the national average range. Given Pepco's familiarity with this type of construction and its local permitting requirements, Shaw Consultants also assumed 0.4% for its permitting cost.
- The cost for removal of overhead distribution facilities is not specifically addressed in RS Means. Pepco used 0.8% of the total project cost for removal cost in their 2006 estimate. Again, given Pepco's familiarity with this type of construction, Shaw Consultants assumed Pepco's estimate of 0.8% for removal costs as well.
- Project management and overhead costs in RS Means vary based on the scope of a given project. For projects with a total project cost in excess of $10 million, such as the current project, RS Means recommends a 3.9% cost adder be applied. Overhead costs represent those costs of a construction project not directly associated with the installation of construction materials, and include both project specific as well as main office costs. For a project in excess

of $10 million, these costs are estimated by RS Means to be 15% of the total construction cost of a project.

- A contingency adder is necessary in order to account for unknowns associated with a project in its preliminary stages of design such as this one. RS Means suggests a 20% construction cost contingency be included as part of a construction cost estimate.

Exhibit 64 summarizes the indirect and miscellaneous project costs Shaw Consultants assumed for its cost estimate based on the previous discussion. In total these costs amount to approximately a $9 million adder.

Exhibit 64 Indirect & Miscellaneous Project Related Costs

	% Adder	Total
Engineering	7.1%	$1,360,264
Permits	0.4%	$76,635
Removal Costs	0.8%	$153,269
Project Management	3.9%	$747,187
Overhead	15%	$2,873,798
Contingency	20%	$3,831,730
Total		**$9,042,884**

5.1.6 Total Cost Summary

The total costs to underground the mainline primary on Feeder 14007 broken down by category as developed by Shaw Consultants using the RS Means database are detailed in Exhibit 65.

Exhibit 65 Shaw Consultants Primary Mainline Estimate Using RS Means

Item	Cost	Cost per Mile
Primary Mainline		
Cable	$ 1,917,980	$ 206,679
Conduit	$ 14,391,023	$ 1,550,757
Manholes	$ 995,325	$ 107,255
Primary Mainline Subtotal	**$ 17,304,328**	**$ 1.9 million**
Labor Productivity Adjustment	$ 1,854,324	$ 199,819
Engineering	$ 1,360,264	$ 146,580
Permits	$ 76,635	$ 8,258
Removal Costs	$ 153,269	$ 16,516
Project Management	$ 747,187	$ 80,516
Overheads	$ 2,873,798	$ 309,677
Contingency	$ 3,831,730	$ 412,902
Primary Mainline Total	**$ 28,201,535**	**$ 3.0 million**

RS Means provides both a national average for construction cost and regional adjustment factors for major cities across the United States based on local information related to labor and material costs. The $28.2 million estimate detailed in Exhibit 8 is based on national averages. RS Means estimates that costs in the District of Columbia on average should be 99.1% of the national average. By applying this 99.1% multiplier to the total project cost of $28.2 million the cost estimate is adjusted slightly lower to $27.9 million. On a per mile basis the cost remains the same due to rounding at approximately $3.0 million per mile.

Overall, the Shaw Consultants estimated total cost to underground the overhead primary mainline portion of Feeder 14007 at $3.0 million per mile compares favorably with the original 2006 Pepco estimate of $3.5 million per mile for primary mainline (excluding transformer and switch costs). The difference in these cost estimates is not considered significant given the scope of the project and the typical variations one would expect when comparing regional averages to specific local experience. In the following section of this report, in order to further explore the reasonableness of both the Shaw Consultants and Pepco 2006 estimates, we compare both to the actual experience of the City of Anaheim, California.

5.2 Anaheim Undergrounding Project Cost Comparison

For additional insight into the cost to underground, Shaw Consultants researched available public information to find projects that approximate the effort required to underground facilities in the District. This search uncovered a similar on-going project in Anaheim, California which is in its 19th year of a 50 year underground conversion plan. This project provides good reference for cost comparison.

The City of Anaheim is currently undergrounding both its primary distribution and 69 kV sub-transmission systems throughout the city. Anaheim did not have a reliability issue; rather the project was justified as part of an overall beautification effort for the city. Heavily developed areas and main arteries are the initial focus of the undergrounding project.

Anaheim's recent historical average cost and projected cost associated with replacing the distribution primary mainline (i.e. excluding the sub-transmission) system alone are as follows:

- For the 2007 and 2008 the average was $3.5 million per mile.
- Actual 2009 through July is $3.4 million per mile.
- Current estimates for 2010 and beyond are $3.8 million per mile.

In order to account for regional variations the RS Means regional adjustment factors were applied to the Anaheim costs to allow for a cost comparison between the District and Anaheim. As mentioned previously RS Means estimates that District costs are 99.1% or below the national average, while Anaheim costs are 107.4% above the national average. Therefore, in order to compare District and Anaheim costs on an equal footing the District cost should be approximately 92.3%[11] of Anaheim costs, according to RS Means.

In the previous section of this report Shaw Consultants estimated the cost for undergrounding the distribution primary mainline at $3.0 million per mile. From 2007 through July 2009 the average cost incurred by Anaheim was $3.5 million per mile. To put this Anaheim cost on an equal footing with the District estimates the $3.5 million Anaheim cost must be reduced by applying the 92.3% factor which

[11] Ratio of .991/1.074 = .9227 or 92.3%

results in a District equivalent cost of $3.2 million per mile for the Anaheim project. Exhibit 66 compares the historical cost to underground the primary mainline for the City of Anaheim to both the Pepco and Shaw Consultants cost estimates.

Exhibit 66 Primary Mainline Undergrounding Cost Comparison

Basis	Cost per Mile
Anaheim Experience	$3.2 million
Pepco Estimate	$3.5 million
Shaw Consultants Estimate	$3.0 million

Overall, the variations in these estimated costs compare favorably with the original 2006 Pepco estimate of $3.5 million per mile. The difference in these cost estimates is not considered significant, as mentioned previously, given the scope of the project and the typical variations one would expect when comparing regional averages to specific local experience. The inclusion of the actual costs associated with the Anaheim project provides further substantiation to the reasonableness of both the Pepco and Shaw Consultants estimates.

6 Feasibility of Undergrounding Existing Assets

In order to explore the feasibility of undergrounding the existing overhead facilities in the District, three undergrounding options are evaluated. The three options considered for analysis are:

1. Underground all existing OH assets, including both primary and secondary
2. Underground only the existing primary overhead assets, both mainline and laterals
3. Underground only the mainline primary overhead assets

For each option the number of circuit-miles, the estimated costs, the estimated project duration, and the advantages and disadvantages of each are detailed. For each option, Feeder 14007 serves as the basis to extrapolate the cost and reliability improvements to the entire Pepco DC system.

In this analysis the following statistics are common to all three options:

Feeder 14007:

- 9.28 circuit-miles of primary
  - 4.25 circuit-miles of 3Φ mainline primary
  - .89 circuit-miles of 3Φ laterals
  - 4.14 circuit-miles of 1Φ laterals
- 9.4 circuit-miles of mainline secondary
- 1619 OH customers

Pepco Total DC Feeders:

- 660 circuit-miles of Primary
  - 320 circuit-miles of 3Φ mainline primary
  - 340 circuit-miles of 3Φ, 2Φ, 1Φ laterals
- 660 circuit-miles of mainline secondary
- 72,252 overhead services

The summary of outage performance statistics in Exhibit 67 form the basis for determining the outage incident improvement that would be expected by undergrounding assets for each of the options considered.

Exhibit 67 Average Annual Incidents per Mile, 2004-2008

Outages	All Outages	Primary	Secondary	Non-Storm	Storm
OH	2.9	2.1	0.85	2.54	0.37
UG	1.4	0.72	0.69	1.41	0.01
Improvement	1.5	1.3	0.16	1.14	0.36

6.1 Option 1 – Underground All Existing Overhead Assets

This option, initially developed by Pepco in their 2006 study, includes the undergrounding of all the overhead assets: primary, mainline secondary, and customer service conductors, transformers, and capacitors, streetlight feeds, and the removal of any associated overhead Pepco assets. It should be recognized that this assessment does not include the cost of undergrounding the other pole attachments, thereby reducing the aesthetic improvement somewhat since the poles would be required to remain in place to service the other utilities.

6.1.1 Reliability Improvement

By placing all the overhead assets underground the following reliability improvements would be realized for Feeder 14007 based on the outage statistics in Exhibit 67.

- **Primary -** The most significant improvement comes as a result of placing the primary overhead underground. In the case of Feeder 14007, with 9.28 circuit-miles of primary and a rate of 1.4 incidents per mile, the average would be approximately 13 fewer outage incidents per year.
- **Secondary -** Undergrounding the secondary provides a net benefit of only 0.16 incidents per circuit-mile, which also includes any individual services that failed. With the mainline secondary estimated at 9.4 circuit-miles (the exact length was not available from the Pepco GIS system), the benefit for the entire feeder would be approximately 1.5 incidents per year, which would affect an average of only 1.8 customers. Overall, there were 29 average annual OH secondary incidents on the 10 average feeders with a total of only 52 customers affected, which is a rather insignificant contribution to the SAIFI or SAIDI statistics.
- **Transformers -** There were no specific transformer incidents on the 10 average feeders that were identified as OH transformer failures. Since transformers are also likely to fail in the underground system, with a failure rate similar to overhead transformers, no net benefits have been included as none were identified.

Extrapolating these results to the entire Pepco DC Service Area one would expect the following improvement system-wide.

- **660 circuit miles of primary –** With 1.4 incidents per circuit-mile, there would be 924 fewer overhead incidents on average – this is roughly half of the 1,753 outages that occurred (non-storm) on the 754 feeders during the 2008 calendar year in the DC area.
- **Secondary -** Contributes only 0.16 incidents per circuit-mile, including any services that may fail. With the mainline secondary estimated at 660 circuit miles, the benefit for the entire system would be 106 incidents per year, but with an average of only 1.8 customers affected per incident, the impact would translate to 190 customers per year. This is a small improvement, with 72,252 overhead services, to the SAIFI or SAIDI statistics.
- **Transformers** - There were no specific transformer incidents on the 10 average feeders that were identified as OH transformer failures. No net benefits have been included as none were identified.

6.1.2 Costs

The following is an estimate of the costs to underground the 14007 Feeder and its extrapolation to the entire Pepco DC system using the unit costs.

Exhibit 68 Cost Estimate for Feeder 14007 and Pepco DC, Option 1

Item	14007 Feeder Cost	Per Unit Cost	Extrapolated Pepco Total DC Cost
Primary Mainline			
Conduit and Cable	$ 29,806,689	$ 3,211,928/mile	$ 2,119,872,278
Splice and Manhole	$ 2,009,892	$ 216,583/mile	$ 142,944,905
Switch manholes	$ 459,453	$ 49,510/mile	$ 32,676,614
Mainline Subtotal	**$ 32,276,034**	**$ 3,478,021/mile**	**$ 2,295,493,797**
Transformers	$ 10,881,955	$ 1,172,624/mile	$ 773,932,144
Total Primary	$ 43,157,989	$ 4,650,645/mile	$ 3,069,425,942
Secondary Mainlines	$ 39,065,680	$ 24,130/customer	$ 1,743,440,760
Commercial Service	$ 393,158	$ 7,021/customer	$ 101,150,000
Commercial Service	$ 877,785	$ 15,675/customer	N/A
Residential Service	$ 16,962,231	$ 10,852/customer	$ 627,736,331
Residential Service	$ 3,502,354	$ 2,241/customer	N/A
Street Light Costs	$ 2,928,875	$ 315,612/mile	$ 208,303,610
DC Permit Costs	$ 403,572	0.3776%	$ 21,712,214
Removal Costs	$ 818,944	0.7662%	$ 44,056,934
Total	**$108,110,588**		**$ 5,815,825,791**

Based on this analysis, if Pepco's customers were to invest a total of $5.8 Billion, they could expect a decrease of 1,030 outage incidents by placing the lines underground. This option has an initial cost of $5.6 Million per incident eliminated.

6.1.3 Advantages and Disadvantages of Option 1

Undergrounding all overhead assets is the most expensive of the three options being considered in this report. While this option does provide the greatest overall benefit in reliability, the bulk of the benefits derived from this option are from improvements in aesthetics rather than reliability. The other options considered in the report are far more cost-effective alternatives for improving reliability. While not reaching quite the same level of reliability as this option, they do achieve significant levels of reliability at a comparatively much lower cost, albeit without the same improvement in aesthetics. The cost per avoided outage for this option is the highest of the three options being considered and requires a much more significant level of construction activity that will require many more years to complete than the other options.

Exhibit 69 presents a list of the advantages and disadvantages of this option.

Exhibit 69 Advantages vs. Disadvantages of Option 1

Advantages	Disadvantages
All Pepco assets would be removed from the poles	Unless telephone, cable and fire alarm systems agree to underground as well a number of poles would need to remain reducing the aesthetic benefit
The current $4 million annual tree trimming budget would be eliminated	Pepco would no longer assist with tree removal in the District which may increase the cost for other utilities
Reliability would be improved	Customers may be required to make changes to their service entrance at their expense
	Every customer's yard would require excavation
	Most expensive solution per circuit-mile
	Requires the largest rate increase
	Requires a long construction schedule to complete
	Requires the most construction and damage to roadways, walkways, yards, and trees, and the most road repaving

6.2 Option 2 – UG Mainline Primary and Laterals

This option places only the lateral and mainline primary underground, while leaving the transformers and mainline secondary on the existing poles. There are two design alternatives under this option listed here for possible consideration; both are based on providing an electrical supply from the underground system to energize the transformers.

- Alternative 1 – utilize some of the existing primary to rise out of the underground and energize sections, usually single phase to energize the distribution transformers. The OH primary would be used to pick up no more than 6 transformers and be isolated from other OH primary conductors. With the 135 OH transformers on Feeder 14007 this would require 25 to 30 risers, resulting in most of the existing OH 3Φ primary being converted to single phase by removing the cross arm and two phases.
- Alternative 2 – the less preferred method would be to rise up on every pole with a transformer, for either a single or a three phase bank as necessary to energize the secondary. This would be aesthetically more pleasing, but require many risers. Feeder 14007 presently has 135 overhead transformers; each riser exposes the UG to a fault should a pole be hit by a vehicle.

Both design alternatives would be expected to have similar costs and reliability benefits and are treated as equal in this Section of the report.

6.2.1 Reliability Improvement

Based on placing all the overhead primary assets underground the following reliability improvements would be realized for Feeder 14007:

- **Primary** – As was the case with Option 1, the most significant improvement comes as a result of placing the primary overhead underground. In the case of Feeder 14007, with 9.28 miles of primary and a rate of 1.4 incidents per mile, the average would be approximately 13 fewer outage incidents per year.

- **Secondary** – Since no secondary assets were placed underground with this option no change in reliability would be expected.

Extrapolating these results to the entire Pepco DC Service Area one would expect the following improvement system-wide:

- **660 circuit-miles of primary** - With 1.4 incidents per mile, there would be 924 fewer overhead incidents on average, this is roughly half of the 1,753 outages that occurred (non-storm) on the 754 feeders during the 2008 calendar year in the DC area.
- **Secondary** - No change in reliability is expected.

6.2.2 Costs

The following is a breakdown estimate of the costs for Feeder 14007 and its extrapolation to the entire Pepco DC system using the unit costs.

Exhibit 70 Cost Estimate for Feeder 14007 and Pepco DC, Option 2

Item	14007 Feeder Cost	Per Unit Cost	Extrapolated Pepco Total DC Cost
Primary Mainline			
Conduit and Cable	$ 29,806,689	$ 3,211,928/mile	$ 2,119,872,278
Splice and Manhole	$ 2,009,892	$ 216,583/mile	$ 142,944,905
Switch manholes	$ 459,453	$ 49,510/mile	$ 32,676,614
Mainline Subtotal	**$ 32,276,034**	**$ 3,478,021/mile**	**$ 2,295,493,797**
Transformers	N/A	N/A	N/A
Total Primary	$32,276,034	$ **3,478,021/mile**	**$ 2,295,493,797**
Secondary Mainlines	N/A	N/A	N/A
Commercial Service	N/A	N/A	N/A
Commercial Service	N/A	N/A	N/A
Residential Service	N/A	N/A	N/A
Residential Service	N/A	N/A	N/A
Street Light Costs	N/A	N/A	N/A
DC Permit Costs	$ 121,874	0.3776%	$ 8,667,785
Removal Costs/Risers	$ 247,299	0.7662%	$ 17,588,073
Total	**$ 32,645,207**		**$ 2,321,749,655**

If Pepco and their customers were to invest a total of $2.3 Billion, they could expect a total decrease of 924 outage incidents by placing the lines underground.

6.2.3 Advantages and Disadvantages of Option 2

Compared to Option 1, this is a far more cost-effective solution that takes advantage of the fact that the majority of OH outages that affect 87% of the customers occur due to OH primary incidents. Based on the Pepco average from 2004-2008, 924 outages would be eliminated annually, with an initial construction cost of $2.5 Million per incident eliminated.

Exhibit 71 outlines the advantages and disadvantages of undergrounding the existing overhead primary assets only.

Exhibit 71 Advantages vs. Disadvantages of Option 2

Advantages	Disadvantages
Moves only assets required to significantly improve reliability	Electric secondary, Telephone, cable and fire alarm would still be on poles which would need to remain
$4 million annual tree trimming budget would be reduced	Pepco could select when and if to help with tree removal as sections of primary are replaced with risers
Reliability would be improved nearly equally to Option 1 for less than 25% the cost	Few if any poles would be removed, reducing the aesthetic benefits
Customers' services are not affected	Storms and non-storm events will still effect secondary for 13% of the OH customers
No outlay of funds by customers	Secondary wires still visible and involved with trees
No yard work required	Tree trimming is still required
Requires smaller rate increase for financing	Requires 660 miles of construction and associated damage to roadways, walkways, and trees

6.3 Option 3 – UG Mainline Primary

This option recognizes that the greatest numbers of customers are affected when the mainline of a feeder is interrupted. When the mainline is interrupted all the customers on both the mainline and the laterals are interrupted.

Based on the numbers of customers affected, feeder demographics and, length of the laterals, which vary from feeder to feeder, typically mainline outages affect at least twice the number the customers per outage event than a primary lateral alone. In addition, restoration of primary mainlines is more time consuming.

6.3.1 Reliability Improvement

Based on placing all the overhead primary assets underground the following reliability improvements would be realized for Feeder 14007:

- **Primary** – Significant improvement comes as a result of placing the primary overhead underground. In the case of Feeder 14007, with 4.25 miles of mainline primary and 1.4 incidents per mile, the average would be approximately 6 fewer outage incidents per year.
- **Secondary –** As was the case with Option 2, no change in reliability would be expected.

Extrapolating these results to the entire Pepco DC Service Area, one would expect the following improvement system-wide:

- **Primary:** 320 circuit-miles of mainline primary exist, and with 1.4 incidents per mile, there would be 462 fewer overhead incidents on average, this is roughly one quarter of the 1,753 outages that occurred (non-storm) on the 754 feeders during the 2008 calendar year in the DC area. However these outages represent 65% of the customers affected.
- **Secondary**: No change in reliability expected.

6.3.2 Costs

The costs associated with Option 3 are documented in Exhibit 72.

Exhibit 72 Cost Estimate for Feeder 14007 and Pepco DC, Option 3

Item	14007 Cost	Per Unit Cost	Pepco DC Cost
Primary Mainline			
Conduit and Cable	$ 29,806,689	$ 3,211,928/mile	$ 1,027,816,862
Splice and Manhole	$ 2,009,892	$ 216,583/mile	$ 69,306,621
Switch manholes	$ 459,453	$ 49,510/mile	$ 15,843,207
Mainline Subtotal	**$ 32,276,034**	**$ 3,478,021/mile**	**$ 1,112,966,690**
Transformers	N/A	N/A	N/A
Total Primary	$ 32,276,034	$ 3,478,021/mile	$ 1,112,966,690
Secondary Mainlines	N/A	N/A	N/A
Commercial Service	N/A	N/A	N/A
Commercial Service	N/A	N/A	N/A
Residential Service	N/A	N/A	N/A
Residential Service	N/A	N/A	N/A
Street Light Costs	N/A	N/A	N/A
DC Permit Costs	$ 121,874	0.3776%	$ 4,202,562
Removal Costs/Risers	$ 247,299	0.7662%	$ 8,527,551
Total	**$ 32,645,207**		**$ 1,125,696,803**

6.3.3 Advantages and Disadvantages of Option 3

Option 3 is the least costly solution of those considered, recognizing that outages on the mainline primary typically affect the largest number of customers per incident. Based on the historic averages, 462 outages would be eliminated annually with an initial construction cost of $2.4 Million per outage incident eliminated.

Exhibit 73 presents a list of the advantages and disadvantages of this option.

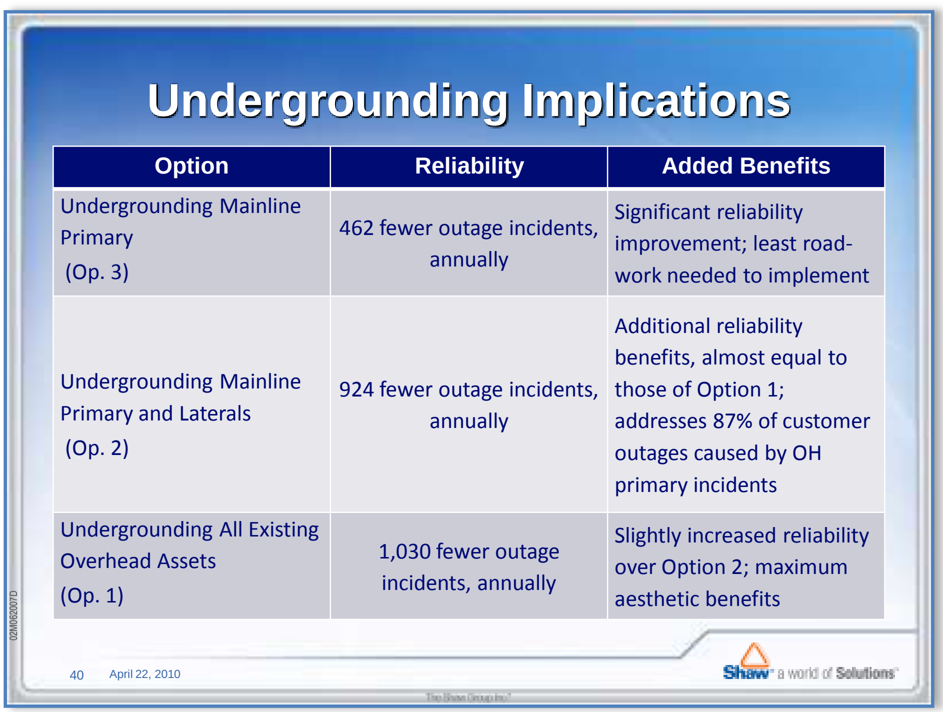
Exhibit 73 Advantages vs. Disadvantages of Option 3

Advantages	Disadvantages
Moves only assets required to significantly improve reliability-mainlines	Electric primary laterals still OH All mainline secondary remain pole mounted
Reliability would be improved at a lower overall cost	Telephone, cable, and fire alarm would still be on poles which would need to remain in place so the aesthetic benefits are reduced
$4 million annual tree trimming budget would be reduced	Pepco could select when and if to help with tree removal as sections of primary can be replaced with risers
Requires approx.50% less road work – 320 miles	Few if any poles would be removed
Customers' services are not affected	Storms and non-storm events will still affect laterals and secondary
No outlay of funds by customers	Wires still visible and involved with trees
No yard work required	Tree trimming of laterals is still required
Requires smaller rate increase for financing	Requires 320 miles of construction and damage to roadways, walkways, and trees

6.4 Feasibility Of Options

Overall, based on this analysis, Option 3 represents the most cost-effective solution if reliability is the number one concern. However, if aesthetics are a major driver, Option 1 is the only approach that has the potential to eliminate all overhead construction and its associated visual impacts. Exhibit 74 summarizes the implications of each of the three options.

Exhibit 74 Underground Implications



Undergrounding Implications

Option	Reliability	Added Benefits
Undergrounding Mainline Primary (Op. 3)	462 fewer outage incidents, annually	Significant reliability improvement; least road-work needed to implement
Undergrounding Mainline Primary and Laterals (Op. 2)	924 fewer outage incidents, annually	Additional reliability benefits, almost equal to those of Option 1; addresses 87% of customer outages caused by OH primary incidents
Undergrounding All Existing Overhead Assets (Op. 1)	1,030 fewer outage incidents, annually	Slightly increased reliability over Option 2; maximum aesthetic benefits

6.5 Other Considerations

Section 7 of this report investigated the other benefits and costs associated with undergrounding that remain difficult to quantify, at best. These include business impacts of construction, tourist implications of long-term construction in the nation's capital, inconvenience for residents and safety issues, to name a few. Adding these costs to the analysis would require significant additional research to put a value on the issues.

One way to mitigate the costs but retain a significant portion of the reliability and aesthetic benefits is a targeted approach where all overhead assets are replaced on a limited basis based on selection criteria related to frequency and duration of outage events, customers willing to participate, and other demographics. In particular, Pepco or the Commission could identify "opportunities" for undergrounding such as when major or minor infrastructure improvements are taking place for other utilities, transportation systems, and road repair.

6.6 Next Steps

Shaw Consultants recommends the Commission consider the following actions as part of any further investigation into the advisability of undergrounding:

- In order to assess the appropriate priority for undergrounding, the Commission should work with the extensive data in this report to develop decision criteria for future undergrounding opportunities so that there is no uncertainty for Pepco relative to cost recovery and support for a decision to invest.
- Targeted undergrounding opportunities should be explored in greater detail based on the decision criteria developed as per the previous bullet, which might include historical frequency and duration of outage events, customers' willingness to pay, and the availability of joint opportunities to cost share.
- The cost implications of retiring undepreciated, fully functioning overhead assets would have to be considered by the Commission for any undergrounding project (e.g., stranded cost of undepreciated amounts).

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7 Other Consideration of Undergrounding

Shaw Consultants reviewed more than fifteen reports in our evaluation of the impacts of undergrounding to natural and human environments. These reports were researched and summarized to identify the impacts from both construction and operational viewpoints, and the positive and negative costs, where available. Costs and impacts presented can be characterized as qualitative, or value-based, as well as quantitative, or financially-based, where possible.

The construction process associated with burying regional or district utility lines is generally conducted as a “cut-and-cover” operation. This method of construction involves, first, cutting or removing the surface materials, and then placing the requisite utilities and their own directly related infrastructure, including bedding, conduit, spacers, protective caps and markers, and the specified backfill material underground. This operation is generally conducted through what is frequently called ‘stovepipe-construction’ wherein whatever portion of trench can be handled in a day is what is excavated - the utilities are installed and the trench is backfilled in day-by-day segments. In residential or commercial areas, or in almost any area with traffic, this use of stovepipe-construction is frequently requested by the local Departments of Public Works, which typically require trench to be completed, or at least plated, at the end of each day or work period. This results in a type of construction that approaches, is part of, and then departs from, any particular area as an entire unit and is not stretched out over long distances, with the resultant long duration of any of the impacts to be discussed below. Even at their most intense, they are generally of relatively short duration.

None of the reports that were reviewed for this analysis included discussions of the ramifications of construction on natural or human environments. However, information is available in general literature for many of these impacts, and this information has been summarized to complement the professional experience of Shaw Consultants staff.

7.1 Environmental Impacts

Impacts on the environment and on the natural surroundings adjacent to utility infrastructure undergrounding sites include concerns relative to noise, storm water run-off, wildlife, and vegetation. Most of the natural and human impacts from the undergrounding of utilities, unrelated to reliability and cost, are aesthetic and biological. These impacts are particularly hard to quantify. Quanta Technology (Quanta Technology 2008), in their attempt to develop a mathematical model, found it particularly difficult to put a value on these impacts. They state that

> … Some benefit categories are intangible, such as the aesthetic benefits associated with the projects and the improved property values. They are conceptually valid, and are often the main project driving force behind undergrounding. It is typically infeasible to meaningfully quantify them in engineering or economic terms, but the model does allow these classes of costs and benefits to be included along with other costs and benefits. For example, the user can define a cost category of “improved aesthetics” and assign a value of $100 million after a project is completed. The model will keep track of these costs, but it is simply reflecting the value inputted by the user.

As such, the natural and human impacts discussed below are based mostly on value judgments. However, there is a growing library of literature that is beginning to place a value on these benefits.

7.1.1 Noise

Noise-related impacts during construction are primarily associated with the operation of heavy equipment during trench excavation, tunneling, or drilling; this is generally associated with the need to excavate under culverts and occasionally under roots of valuable trees, occasional blasting where rock is encountered, the placement of conduit & cable in trenches, and the backfilling, paving, and replacement of soil. Levels of noise during construction are generally controlled by local or regional noise ordinances and conditions in local street opening permits, although these ordinances are not always adhered to. Noise disturbances can be managed by shifting the time of day when work is being completed, so that activities in residential areas might be conducted during the day and activities in commercial areas might be conducted at night. It should be noted that nighttime construction schedules can often require an increased cost. As discussed previously, these construction timeframes, and therefore their associated impacts, are generally of relatively short duration.

Relative to underground utility operations, there are minimal noise concerns to consider, as there are only slight differences between overhead and underground operations. In rare cases, high voltage overhead power lines may emit a noticeable hum during rainy or even very humid weather. This hum is eliminated when power lines are undergrounded. In addition, depending on how a power line is undergrounded, the electro-magnetic field emitted by most electric lines can be neutralized through the effects of undergrounding.

7.1.2 Storm Water Run-off

As the undergrounding of most utilities does not involve the altering of the terrain to any great extent, the storm water impacts would be more related to the transport of sediments into local waterways, than they would be to any changes in storm water flow itself. Assuming that the undergrounding of most local utilities would be using stovepipe-construction techniques, the sediment impacts would be related to: the length of trench opened on a given day; the weather, as it relates to rainfall; and the proximity of each day's worksite to catch-basins, drainage swales, and waterways. The condition of the trench and construction area after the crew has moved on could contribute to storm water impacts and sediment transport, but construction under pavement or sidewalks could quickly be repaired, and construction under lawns or open grassy areas can be minimized with mulching and rapid re-vegetation of the site. Depending on the type of construction within the trench, the local ordinances, and the placement of erosion and sedimentation controls, a contractor may be required to stop work or even cancel a day of work if rain is anticipated. In a well-managed construction project, impacts from sediment transport should be relatively minor.

The presence and operation of overhead utility lines is unlikely to have much of a direct impact on storm water quantity or quality. However, the better developed the urban forest – including that component found along the streets in any given community – the greater the reduction in storm water treatment cost and flood control cost (Bell, & Wheeler 2006).

7.1.3 Wildlife

Impacts on wildlife during the installation of underground utility infrastructure should be relatively minor, as long as the construction corridor is confined to previously disturbed area such as roads, sidewalks, or lawns. The presence of construction crews, construction noise, dust, and other disturbances would certainly drive most mobile wildlife out of the immediate area for the duration of the construction. However, these animals would more than likely return as soon as the activity level returned to normal.

The health of the wildlife population of any given area is directly related to the health, diversity, and physical structure of its vegetation. A mowed lawn can certainly provide more habitats for wildlife than a paved parking lot, but it lacks diversity and physical structure. A long row of well formed shade trees can provide the necessary habitat to support a much more diverse wildlife population, especially in conjunction with other vegetated sites in the area, than a community limited to lawns, shrub, and flower gardens. Thus, the removal of overhead utilities can lead to substantially improved natural environment through the increased ability for the area to support a diverse vegetation structure.

7.1.4 Vegetation

Undergrounding utilities and utility infrastructures causes the most noticeable impacts on local trees. Even in an environment where a tree has been allowed to develop its natural spread of roots, the excavation of a utility trench in close proximity to the trunk can remove as much as 40% of a tree's roots (Mercker, D). In the case where a tree is growing in the grassy strip between a road and a sidewalk, the situation may be more problematic. Because of the complete lack of air and the heavy compaction of dirt, trees will almost never develop any roots under a road. This is very stressful on a tree, but has the advantage that, if the utility trench is placed in the road, tree root disruption is generally diminished. Trees are able to develop a root system in the grassy strip and possibly under the sidewalk and into lawn areas beyond. If the utilities are placed under the sidewalk, the excavation of the trench can have a devastating impact on a tree. According to David Mercker (Mercker, D) of the University of Tennessee Agricultural Extension Service, the only practical way to protect the roots of a tree in this situation would be to tunnel under the root system. Whereas most of the impacts associated with construction activities are short term, the severing of a major portion of the roots of an already stressed tree is likely to be catastrophic in terms of the survival of the tree.

In the report prepared for Florida Electric Utilities, Infrasource (2007) made the case for the improved tree canopies allowed by removing overhead utilities, at least in terms of the aesthetic value of the trees. They said:

> …The preservation of existing trees can be considered an extension of improved aesthetics: the interaction of undergrounding with the tree canopy is often discussed separately, too. When overhead power lines have been removed, existing trees no longer have to be trimmed frequently and can thus grow into more pleasing, full shapes. This also creates an opportunity to replace every pole with a new tree, to have taller trees and to plant faster growing types of trees, without worry of any risk to them through trimming.

Another consideration includes the damage to the root system of trees, caused by the construction of the utility trench. Trees so affected would certainly be weakened and would probably have to be removed earlier than would otherwise be the case. As long as the community is willing to mitigate this effect and replace affected trees, the impact would be overcome during future generations. If the utility trench is placed under a sidewalk, as presented above, replacement trees would best be placed in areas that reduce the potential impact to their roots that would occur in the event that maintenance is required on the underground utilities. Likewise, the utilities should be so designed and constructed (possibly in conduits) so as to reduce the need for damaging mature tree roots during maintenance.

7.1.5 Human & Natural Environment Benefits

There are numerous human benefits and benefits to the natural environment of larger and more stable tree canopies, which are allowed due to the undergrounding of overhead utilities. These include social justice issues, carbon sequestration, and energy saving through shading and wind reduction. Probably the most notable is the improvement in air quality and the health of people who reside, visit, and or work in and around urban areas (Nowak 2006). Nowak demonstrated this through the development of the Urban Forest Effects (UFORE), sponsored by the US Forest Service. He concludes his 2006 article, in the cautious manner of a forest scientist, as follows:

> Urban forests can improve environmental quality in urban areas. The types and magnitude of these improvements need to be accurately quantified. If vegetation effects are demonstrated to improve environmental quality, then programs/regulations designed to improve environmental quality can and should consider incorporating urban vegetation as a means to meeting established quality goals. Establishment of urban forestry programs to meet environmental quality standards can be a cost-effective "biotechnological" means to meet multiple standards (e.g., air and water quality, greenhouse gas emission reduction) as trees provide multiple benefits for a singular cost.

The long-term value of the urban forest must be considered in developing the cost/benefit ratio of the natural and human environments of the urban forest, as compared to the short-term cost of undergrounding the existing utilities. As these values become even better defined, it should be possible to make a direct comparison in a mathematical and economic fashion between these two seemingly diametrically opposed scenarios.

7.2 Impacts on Residents, Short-Term Residents, and Visitors

Residential areas would be most sensitive, and therefore most disturbed during the night when the residents are sleeping, as well as during commuting times when individuals are trying to get to and from work, or school, for example. Areas with residents that are home during the day would be impacted by noise, child safety, and access issues, to name a few.

As stated by Quanta Technology (2008), aesthetic benefits are conceptually valid, and are often the main project driving force behind undergrounding, but it is typically infeasible to meaningfully quantify them in engineering or economic terms. The factors driving the aesthetic improvement include the removal of the rather unsightly poles and overhead wires, and the undisturbed view, and in many cases the development of, beautiful, well-formed trees. The aesthetic value of the view of a continuous line of large shade trees along a tree lined boulevard has tremendous appeal to many people. This can be demonstrated by the increase in property values for this type of residential area (Bell, & Wheeler 2006). As the increase in property values also translates into an increase in property taxes, there is a direct human beneficial impact from the removal of the overhead lines and the improvement in the urban tree canopy.

7.3 Business and Commercial Impacts

Commercial impacts of utility undergrounding tend to occur during the day and would begin with the first removal of trench material and do not end until the trench is backfilled. If construction proceeds down the street in front of retail establishments, the location of the trench and the operation of the construction crews will frequently take up all available parking and may block access to these establishments. This can result in reduction or even total loss of business during the period of construction. Even if access is provided, noise and other annoyances such as dust or the proximity of the construction force may make customers uncomfortable and thereby reduce sales.

Impacts to commercial and retail establishments by undergrounding nearby overhead utilities are primarily aesthetic, but can result in financial benefits. There is literature available that demonstrates the value of having a healthy urban forest in the neighborhood of retail and commercial establishments

(Bell & Wheeler 2006). Bell & Wheeler also demonstrate that this impact can even be seen in terms of improved sales in local stores.

7.4 Impacts of Undergrounding on Road Transportation

Transportation related benefits of underground vs. overhead utility lines and systems were described in both the 1998 Australian undergrounding report and the 2008 Oklahoma Corporation Commission's report. One of the most significant items in the cost/benefit calculus of the Australian report is the reduction in motor-vehicle accidents caused by collisions with utility poles. The study quantified this benefit over a twenty year period, at $1.1 Billion. Beyond the monetary savings, there are safety benefits that are much harder to quantify. The Oklahoma study noted that

> The American Association of State Highway and Transportation Officers reports approximately 1,000 people lose their lives in the United States every year because of automobile accidents involving utility poles. In Oklahoma, a utility pole was the first thing struck in 822 vehicle accidents in 2006...

Decreasing the amount of road-side targets, like utility poles, presents an opportunity to decrease the number of motor vehicle accidents where utility poles are involved. Also, undergrounding these poles would decrease the ability for poles to be brought down over road ways in weather-related outages.

References

Bell, Ryan & Jennie Wheeler. 2006. Talking Trees – An Urban Forestry Toolkits for Local Governments. ICLEI – Local Governments for Sustainability. 88 pages.

Infrasource Florida. 2007. Undergrounding Assessment Phase 2 Final report: Literature Review and Analysis of Electric distribution Overhead to Underground Conversion. Prepared for: Florida Electric Utilities. 59 pages.

Mercker, David. <u>Protecting Trees During Construction</u>. The University of Tennessee Institute of Agriculture, Cooperative Extension Work In Agriculture and Home Economics. 4 pages.

Nowak, David J. 2006. Institutionalizing Urban Forestry as a "Biotechnology" to Improve Environmental Quality. USDA Forest Service, Northeastern Research Station. <u>in</u> Urban Forestry Urban Greening 5. Pages 94 – 100

Quanta Technology Florida, 2008. <u>Undergrounding Assessment Phase 3 *Ex Ante* Cost and Benefit Modeling</u>. May 21st 2008. Prepared for Florida Electric Utilities.

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Appendix A Data Request Communications with Pepco

The data requests provided to Pepco are provided below for reference.

Request 1- June 24, 2009

Memorandum

To: Pepco

From: Shaw Consultants International, Inc.

Date: June 24, 2009

Re: PSC Requested Pepco OH-UG Review – Data Requests

Thank you for arranging these preliminary meetings with the various Pepco staff that have allowed us to understand many of the reliability issues and the data that is available. To help expedite the project we are requesting the information listed below to help us evaluate the WPFs performance against the general population of overhead and underground distribution assets. The requests are broken into two categories – electronic for files that can best be used via computer and hard copy for items such as maps that require a special system such as GIS or hand analysis.

Electronic Files – the requested files which are best described as those that analysis the performance of the OH and UG feeders and contain the detailed backup of the specific outage events. We recognize *some of* these files are based on less than 5 years of data and we may need to request additional information to gain 5 years of history depending on the analysis of the data. **This data was sent promptly – there were some initial mistakes, but they were corrected and resent –no problem.**

The specific files, by name are:

- *We will enter the exact file names here as they are copied.*
-

Reports - Forestry staff mentioned he developed a survey/inventory of the trees problems in the greater Palisades area with annotations and a forward look as the present trees die off. We would appreciate a copy (via e-mail) of the report for review.

We do not have – would help with the question of tree cover asked on the conference call last week

Paper files – in addition to the electronic files we respectfully request hard copy of the following:

- The 13 drawings that staff prepared of the 2008- WPF District feeders, showing the specific feeders' circuit map and the outage(s) location, date, cause, etc.
- The complete GIS maps for the above feeders showing all primary assets down to the transformers. –**Never received**
    - Recognizing the feeders may be 100% OH, 100% UG or a combination of OH and UG, using the ESRI ArcInfo GIS query capabilities, for each of the thirteen feeders please supply:
        - Total primary (mains and laterals, OH and UG) in circuit feet-**Received**
        - Total customers-UG and OH by supply-**Not available?**
        - Total transformers – total connected kVA and the physical number of units OH, URD, and UG – **Received – not broken by UG and OH**
        - 3 Φ Bare OH conductor primary in circuit feet - **Not available**
        - 3 Φ Covered OH (tree wire) conductor in circuit feet - **Not available**
        - 1 Φ Bare OH conductor primary in circuit feet - **Not available**
        - 1 Φ OH covered (tree wire) conductor in circuit feet- **Not available**
        - 3 Φ Paper & Lead conductor primary in circuit feet- **Not available**
        - 1 Φ Paper & Lead conductor primary in circuit feet- **Not available**
        - 3 Φ XLPE conductor primary in circuit feet- **Not available**
        - 1 Φ XLPE conductor primary in circuit feet- **Not available**

- Reference feeders – based on 5 years of SAIFI please supply 7-10 feeders that represent an "average" interruption rate for the period. This should approximate the Pepco SAIFI system average for the 5 years within the District. For these reference feeders please supply the complete outage history for the 5 years so that we may build a history by location similar to that Tony Chou produced for the WPFs for 2008 (Note: we understand no such maps currently exist). **Received**
- Physical circuit maps of the selected feeders-**Never Received – confidentiality?**
- In addition the same information from ESRI for these feeders as for the 13 WPFs which includes:
        - Total primary (mains and laterals, OH and UG) in circuit feet- **Received**
        - Total customers-UG and OH by supply
        - Total transformers – total connected kVA and the physical number of units OH, URD, and UG- **Received – not broken by UG and OH**
        - 3 Φ Bare OH conductor primary in circuit feet - **Not available**
        - 3 Φ covered OH (tree wire) conductor in circuit feet- **Not available**
        - 1 Φ Bare OH conductor primary in circuit feet - **Not available**
        - 1 Φ OH covered (tree wire) conductor in circuit feet - **Not available**
        - 3 Φ Paper & Lead conductor primary in circuit feet- **Not available**
        - 1 Φ Paper & Lead conductor primary in circuit feet- **Not available**
        - 3 Φ XLPE conductor primary in circuit feet- **Not available**
        - 1 Φ XLPE conductor primary in circuit feet - **Not available**

Please send the hardcopy documents to:

Mr. Timothy O'Brien
Shaw Consultants International, Inc.
1 Main Street, Suite 900
Cambridge, MA 02142

Request 2 – July 9, 2009

Memorandum

To: Pepco

From: Shaw Consultants International, Inc.

Date: July 9, 2009

Re: PSC Requested Pepco OH-UG Review – Request for Information/Discussion Items

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After our recent telephone conversations and reviewing the documents we have received to date we have some questions on those documents that we mentioned and also we wanted to confirm our requests for additional materials and data. Let us start out with some questions and clarification points.

2008 WPFs annotated circuit maps: The circuit maps we received with the outage annotations do not agree with the master list of outages shown in files "Priority Feeder Outage History 2008.xls". As examples the annotated outage dates do not agree (consistently one line in the spread sheet off – feeder 14015), outages involving several different durations at or near a site are all lumped and charged the highest minutes or the outage minutes are added. Finally some of the outages in the Excel report are not included on the maps-for example the 14200 feeder with a SAIFI of 4.96 shows only 3 outage incidents. The Pepco team may work these maps a certain way, ignoring some smaller non-storm outages as they are analyzing for total circuit performance. However we will want to have all the correct outage data shown on the proper maps; the .pdf's we were sent were originally created in ESRI ArcMap 9.1.0.766 and annotated and then distilled into .pdf's ---this will not allow us to make additions, changes or corrections. This is an item for our discussion on Thursday as we will need the WPF maps showing the outages correctly displayed to match the outage data.- **Not received**

Outage locations – as I mentioned on the telephone, I was able to find a conversion program (grid to GPS) based on the information you sent and we can locate the outages and view in many cases the Pepco assets at and near the site. We will know where we are for the conference calls next week.

Data received to date questions: The latest report 2007 – 2008 which we have in paper format lists Pepco with 1220 feeders and the two previous similar reports show 1454 feeders. What is the correct number of feeders for Pepco as a whole and the District only we are seeing different totals on the various reports? *After our discussion yesterday*, we understand the correct Pepco District has 760 feeders. We would like to understand (discussion item for next week) why there seems to be different feeder counts on the various documents.- **Covered on conference call**

Undergrounding Cost Estimate – 2006 PSC filing: We had this information request ready to go as I mentioned, so in order to help with the conference call next week, we thought we would let you read thru to understand what we will be looking for. The requested documents and files are best described as any and all that were used to investigate, engineer, design and price the placing of the overhead primary and secondary underground for the entire 14007 Feeder. This will include:

- Circuit maps of the present OH primary and secondary 14007 feeder assets including a feeder cover sheet and all the plates that show the details.
- Field survey documents that were prepared and show the proposed primary and secondary underground work in detail with details of the actual field conditions, such as large trees, the areas requiring re-routing around trees, box trenching and digging areas. These were the maps and records shown to us on June 25, 2009.

Cost estimating back up documents that include: Please make any required changes to the tables to allow for the variances and items not shown in these samples.

- Total feet of trenching broken down as:

Trench Type	Purpose	Construction Type	Concrete encased (Y or N)?	Linear Feet
	Primary Only	8 way – 5”		
	Primary & Secondary	8 way – 5” and 4”		
	Primary Laterals	4 way – 5”		
	Secondary	4 way – 4”		

Trench Type – traditional, box, hand work

- Cable and Wire-Primary

Purpose	Cable type/size	Estimated linear feet	Splicing Points	Notes
Sample – Mainline 3Φ	600 KCM P&L	4000	15	600 KCM Mains and #2 Laterals?

Purpose – Mainlines 3Φ, Lateral 3Φ, Lateral 1Φ. Notes linear feet for 3Φ of 100 feet requires 300 feet of cable, splice points for 3Φ will be understood as meaning 3 splices, etc.

- Cable and Wire-Secondary

Purpose	Cable type/size	Estimated linear feet	Elbows transformers to tap holes	Notes
Sample – Secondary 120/240V	250 KCM	4000		

Purpose – Secondary and service cable – 120/240v, 120/208v - 3Φ, 277/480v 3Φ.

- UG Structures

Purpose	Manhole/hole size	Estimated Number	Notes-Purpose
Sample-Mainline	6’x14’x10’		Transformers (1Φ or 3Φ), Oil Switches., Primary
	6’x12’x10’		
	6’x14’x10’		
	3.5’ X 3.5’		UG
	3’ x 3’		Secondary mainline splice

	other		

- Other Assets

Purpose	Manhole/hole size	Estimated Number	Notes
	Primary Risers		
	Transformers 1Φ		By size
	Transformers 3Φ		By bank size
	Oil switches 3Φ		
	Oil switches 1Φ		
	other		

Note: WMIS produces a work order detail sheet that breaks all the components down by point and span or in this case we understand it was totalized by the various asset by installed purpose. If the Pepco WMIS can produce said report, it will likely suffice for all the above.

None was received as of 8/5/2009—some has arrived TBD what is in the package

The WMIS system compatible unit tables you sent are fairly straight forward, we may ask Cheiho to run thru one or two to be sure we completely understand them. If there are any other costs in the estimate, including vehicles, flaggers, or overheads for stores, etc. that do not appear on the CU tables we will need to understand those. As part of our assignment with the PSC we will compare Pepco cost estimating with industry standards such as RS Means to verify the work that your team performed. As an example RS Means figures the cost of materials and labor and then adds percentages for handling and profit. Some utilities have this all built in and some add these to the job totals.

Understanding that the Pepco estimates were done in 2006 and materials and labor have likely increased in the last few years, we will use the current (2009) compatible unit tables for the comparison and note that in the report – unlikely in a magnitude of order study there will be much effect. One option would be to run the work order Engineering created (update it by adding one unit of plant) and the estimate should be at the current rates (note; this depends on the version and configuration of the WMIS system). When we discuss it next week, he might be able to say the job went up by x% for materials and y% for labor.

Thank you for your help.

Request 3 – July 20, 2009

Memorandum

To: Pepco

From: Shaw Consultants International, Inc.

Date: July 20, 2009

Re: PSC Requested Pepco OH-UG Review – Request for Information/Discussion Items

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Thank you for setting up the conference calls last week; many of our questions were answered and evidently some data we would have liked is simple not available. Please provide the following data and reports to allow us to continue moving forward.

2008 Customer served OH or UG: For the following 25 feeders please provide the 2008 total customer count, the number of customers served from OH facilities and the number of customers served from UG facilities. We note 6 feeders are 100% UG and we only need to confirm total customers. –**Not available**

Feeder Number	Overhead Customers	UG Customers	2008 Total Customers
27			
53			
66			
76			
84			
229			
308			
366			
14015			
14200			
14133			
14703			
14717			
14753			
14755			
14768			
14896			
14900			
15009			
15014			
15174			
15294			

15705			
15706			
15986			

High Priority Feeder and Distribution System Statistics at a Glance 10/1/2007-9/30/2008: During our visit in June we were given the above mentioned report in paper format with no way to dig into the details such as the statistics for the HPF feeders specifically in the District. We request that the report be updated/presented as follows so we can compare our statistics for both average feeders and WPF feeders:

- In the rows designated as *(3) Pepco 28 Priority Feeders* – please break this into two additional sub headings (with the appropriate data)
  - Pepco – District Service Area 15 Priority Feeders – compare as before but only to the Pepco District System Averages
  - Pepco – non-District Area 13 Priority Feeders – Compare as before to the non-District system averages
- The Report Period is presently defined as 10/1/2008 through 9/30/2008, to allow the document to support the 2009 Pepco filing. Using Pepco's Data Mart please change these dates to 1/1/2008 – 12/31/2008 for the entire report. We are requesting this second date range (and report) to allow a comparison against (both) the Pepco 2009 Consolidated Report filing to the PSC and secondly to the 5 year annual history outage reports we were provided.

What was sent was Incorrect—being re-worked – supposedly was to arrive electronically 8/5/2009

District of Columbia Reliability Indices (2004-2008): In the September 30, 2004 Pepco filing to the PSC, the document contains District Reliability Indices[12] by delivery asset type (OH, UG) with and without storms and further breaks down the UG delivery assets (network, radial, etc.). Please provide the same information for reporting years 2004 – 2008. In addition please provide for 2008 the most recent year reported, the number of total Pepco District customers[13] served on all feeders broken down as follows:

Pepco District Customers

Total OH &UG	OH 4kV	OH 13kV	UG 4kV	UG 13kV

Pepco District UG Customers

Network	4 kV Radial	13 kV Radial Loop	Total

[12] Report on the Feasibility of Removing Pre-Existing Aboveground Utility Lines and Cables and Relocating them Underground – Page 12, Table 2.

[13] Recognizing feeders are reconfigured and customer changes made, the latest consolidated OMS quality grade data is sufficient.

Pepco District OH Customers

Voltage	Mainline	Lateral	URD (OH supplied)	Other - define	Total
4 kV					
13 kV					

Note: should there be a conflict or over-lap between URD (OH supplied and 13Kv radial loop) please enter appropriate customers numbers and a clarifying note.

Not available as OH and UG customers are unknown????

District of Columbia Construction Rules and Regulation: Utilities are often subject to local, state and federal ordnances when moving OH assets UG and opening streets, installing conduit and manholes, etc. Could you assemble a list of all the required permits, costs of the permits, agencies and government bodies that will be involved during the construction and after the assets are in the ground. This will include items such as Public Space Occupancy Surcharges (per foot?), Road Opening Fees (per foot?), Permits and Inspections (area, per street, per job?), Flaggers, Allowed hours of construction if limited on streets, etc. A flow chart of the process with explanations including any wait times, costs, the actual process, etc. might be a good way to allow us to gain an understanding of the entire effort and costs involved. **We received this information**

Thank you for your help.

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Appendix B Meeting Notes

The meeting notes are provided below for reference.

Monday, April 13, 2009 – PSC Washington DC Project

Meeting Location: Cambridge

Time: 4:30 – 5:15 PM

Attendees:

Non-Shaw	Role
AmerenUE staff	Manager Reliability Improvements
Shaw Global Team	**Role**
Phil DiDomenico	PM
Timothy J. O'Brien	Consultant
Dick Yanco	Technical PM

Agenda: Conference call with manager of Reliability Improvement at AmerenUE, overseeing $300M Reliability Improvement undergrounding project.

Discussion:

- Please discuss the whole history of the program and the results to date:
  AmerenUE referenced the article in the January 2009 T&D World magazine as telling the story pretty well. Bottom line was the customers were very tired of outages caused by a series and seasons of storms of all types that caused widespread outages of long durations multiple times. AmerenUE after hearing the customers and criticism initiated the Power On project in July of 2007 which is part of a multi- pronged customer reliability and environmental focused improvement program. The reliability improvement program is focused on Storm Driven Reliability improvement – what causes the most restoration issues repeatedly after storms- such as backyard construction that is overgrown with large trees and goes out during most storms and requires a high crew to repair ratio to repair. See CAACI explanation below.

- How bad or what were the reliability numbers (ball park) with and without storms when you started the project? What are/where the SAIFI and CAIDI goals for AmerenUE?
  Average reliability numbers before project without storms were in the second quartile of performance—basically worse than 25% of utilities and better than 50% of the utilities for both

"blue sky" and "storm restoration". This is usually the target utilities shot for on a national bases and want to be the best one or two in their own geographic area.

- The 500 customers you spoke with more upset over repeated outages or long durations during storms?

  Said hard to tell but they were just tired of the interruptions and the durations. He said one issue with the backyard construction were the storm related outages that occurred several weeks after the storms as more branches weakened or broken by the storm fell and caused additional outages.

- Tree trimming –is there much opposition to trimming in all or some areas?

  No, but the trees in some areas like the backyard construction of the 1950's and 1960's have 50 year old 80 and 90 foot trees and they are falling. Tree trimming in backyards is a nightmare as trucks cannot typically get in the yard for the use of the buckets.

- How are the early results going?

  Good for the most part—good press – customers appreciate we are trying to improve the reliability. There have been some customers who said no to the reliability improvements-they did not want a transformer (big green box) on their front lawn. Other areas are going forward as a neighborhood – getting prices from electricians for wholesale replacement of their meter troughs from OH to UG to eliminate the potential of local outages.

- You're working on 200 miles out of 27,000 will this have a real effect (especially in a major storm) or is it an initial effort to see if more is justified? What are the goals for the areas being upgraded- SAIFI and CAIDI

  We are working a number of different projects and we will see the results and move from there. Nothing is set at this point after the initial $300M. Dealing with subdivision from the 50s….backyard service drops with trees that have grown to 80 feet tall will help during storms.
- How does $300M compare to the total installed plant value of the company?

  Unknown – no real answer--but--they are still allowed a rate of return on installed plant – (not yet deregulated with fixed rates?) so this is likely not hurting them if they earn 8-11% return on the newly installed equipment.
- How is this being funded? Rate increases? Will different customers pay different rates for the quality of service (Duquesne example).

  Will request cost be added to rate base after the project(s) completion-see above notes.

- How do customers not getting upgrades feel about these costs? Any feedback yet?

  Not covered

- Could you describe your CAACI formula and how it works? Is it a cross between reliability and engineering economics?

  CAACI or Cost per Annual Avoided Customer Interruption is the filtering system AmerenUE is using to determine which projects offer the greatest "bang for the buck." Areas of high frequency (SAIFI) are looked at for possible improvement and the resulting expected outage frequency is developed –based on the outage causing assets being eliminated. This delta is then used to figure the cost per incident – lowest cost (per avoided interruption) projects are done first.

- Did you develop a set of numbers for different job types to get across the board estimating for jobs?
  Yes—we developed cost per circuit mile for the preliminary screening and then if they are identified as a potential project, a typical project sheet is developed with the actual costs – preliminary and engineering grade estimates

- Other utilities going UG as well (cable, Telephone
  No, no interest on the part of other utilities….so we top the poles and the pole stay, but if AmerenUE is off the pole we are no longer a part owner of the pole. A lot of backyard poles are staying due to the services that are on them – the primary and transformers are gone of these poles.

- Are customers switching their service drops to UG
  Not many at this point – I am not sure any have actually done it.

<u>Tuesday – June 23, 2009 – PSC Washington DC Project</u>

Meeting Location: 3400 Benning Road, NE, Washington DC 20019

Time: <u>9:00 AM – 11:00 AM</u>

Attendees:

Pepco Personnel	Subject Matter-Role
	Project Manager and Coordinator
	OMS Functionality
	OMS Functionality
Shaw Global Team	**Role**
Timothy J. O'Brien	Consultant
Dick Yanco	Technical PM

Agenda: The purpose of the meeting was to gain an understanding of the Pepco OMS system (CES with an Arc-Info GIS interface for the data model).

Discussion: Pepco staff led the discussion and demonstration of the CES system. Key items discussed:

1. Customers are tied to transformers using the CIS system which ties every customer to a transformer. The records of outages for a customer are their relation to the transformers that maintain the records of outages. The transformer level is the most detailed.
2. CES system – features—there are alarms for outages that have lasted over 8 hours, over 100 customers, over 24 hours and so on. The system weighs the customer outages by assigning values to customer accounts such as hospitals (180,000) to prioritize the work.
3. Screens – each outage requires the completing of the OMS field report—
    a. Class – Primary, secondary, bare, covered
    b. Device –
    c. Cause/Problem – if equipment failure they must use Equipment Failure
        i. Equipment Failure – see above
    d. Phase/Phases
    e. Action – Select 1, 2 or 3
    f. Coordinates of problem – Maryland geo-spatial coordinate system
    g. Manhole problems—there are 7 pull down screens
    h. Refer to and follow-on work
    i. Map# is a throw-back to the Alexandria Book of maps
4. Pepco will supply us with the OMS symbols and the pull down screens.
5. New customers updated every day
6. Secondary is not modeled
7. Not every cable is modeled…can't show outage location
8. Brings over some attributes from GIS
9. Can't do spatial queries like GIS
10. No automatic meter reading
11. System slows down in a storm……groups outages during a storm, up to fuse level
12. Storm Mgt software…been implemented for 3 years…calculates # of crews needed

Priorities

AFP assist fire and police

Breaker

Switch

OH fuse

UG fuse

UG transformer

Wire down

Pole

OH transformer

Service

PSO possible service outage

PDO possible device outage

RDO real device outage

<u>Tuesday, June 23, 2009 – PSC Washington DC Project</u>

Meeting Location: 3400 Benning Road, NE, Washington DC 20019

Time: <u>11:00 AM – 3:00 PM</u>

Attendees:

Pepco Personnel	Subject Matter-Role
	Project Manager and Coordinator
	Outage Data & Priority Feeders
	Outage Data & Priority Feeders
	Outage Data & Priority Feeders
Shaw Global Team	**Role**
Timothy J. O'Brien	Consultant
Dick Yanco	Technical PM

Agenda: Pepco analyzes and maintains records of all system interruptions. This group is responsible for extracting and assembling the information for use by Pepco and also for the required filings to the DC PSC.

Discussion:

1. Pepco staff lead a presentation of the data that is extracted from the OMS outage system (electronically) and clarifying data from the free field outage report option manually.
2. OMS generated reports started in June 2008 – similar (from the same source) data is not available for earlier dates. Consolidated Report dated February 2009 has data for WPF for 2008? Full year?
3. Pepco staff went through the various reports – some key reports that are available.
    a. Worst feeders- there are a total of 28 worst feeders in Pepco – 2%. Of these based on feeders, 15 are in DC.
    b. CPI index is used as a weighting tool to help define the worst feeders. It is used in conjunction with the common measurements of SAIFI, SAIDI, but adds the number of interruptions and also the customer hours of interruptions.
    c. Worst feeders are initially sorted by the CPI- the highest indices supposedly being the worst performing feeder. But there is a final review and obvious outliers are eliminated such as the example shown where a feeder had a single incident and a frequency of 6! – Caused by bad data on the customer count.
    d. The worst feeders for the 2008 period that was just reported have the outages plotted against the locations – cause, duration, customers, etc. These maps are available with the outages plotted.
    e. The group has analyzed the WPFs for the SAIFI and SAIDI compared to the total population of the Pepco feeders (without major events) and found some interesting statistics such as the feeders on average are twice as long as the general “population”

of the feeders, but the statistics such as SAIFI and SAIDI are much higher. We will get this.

f. We discussed getting the entire history and maps for the 2008 WPF and for average OH and UG feeders in order to make a comparison.

<u>Wednesday, June 24, 2009 – PSC Washington DC Project</u>

Meeting Location: **Select** 3400 Benning Road, NE, Washington DC 20019

Edison Place 701 Ninth St. NW, Washington, DC 20068

Time: 8:30 AM – 10:00 AM

Attendees:

Pepco Personnel	Subject Matter-Role
	Project Manager and Coordinator
	Standards/UG Secondary Failures
Shaw Global Team	**Role**
Timothy J. O'Brien	Consultant
Dick Yanco	Technical PM

Agenda: To understand design standards for both new and also upgrades to assets.

Discussion:

We met with the head of standards and UG secondary features.

He explained that Pepco has established guidelines for new construction, which he will provide to us, but guidelines contain no reference to switching OH to UG.

Generally, when extending a new feeder, if it is OH, then the OH is extended….if UG then UG extended, but it does depend on the individual situation. They never want to reduce reliability of a feeder when extending.

They use only paper and lead cable for UG radial. They are seeing 40 year life on these cables.

Currently there is a program of upgrading all 4kV to 13kV…long term project.

Using lots of ties for redundancy in radial system

URD is direct buried

Having no problem with Pre Assembled cable (PAC)

Pepco has not been able to use Tripsavers because of their high fault current.

New OH is Tree wire is used for the most part…..cost is only about 10% more.

Wednesday, June 24, 2009 – PSC Washington DC Project

Meeting Location: **Select** 3400 Benning Road, NE, Washington DC 20019

Edison Place 701 Ninth St. NW, Washington, DC 20068

Time: 11:00 AM – 3:00 PM

Attendees:

Pepco Personnel	Subject Matter-Role
	Project Manager and Coordinator
	Staff Forester, Vegetation Mgt
	Lead Urban Forester, Urban Forestry Administration
	DC PSC Chief, Office of Engineering
Shaw Global Team	**Role**
Timothy J. O'Brien	Consultant
Dick Yanco	Technical PM

Agenda: Field tour of areas prone to outages.

Discussion:

Pepco Staff took us thru the Palisades section of DC's Ward 3, an area with 3 feeders that are continually on the WPF list due to the impacts of numerous mature street trees on the OH system. Palisades is an area of modest but expensive homes, possibly due to the large mature areas prevalent in this part of DC.

He explained their vegetation management procedure, including communications with residents, and recent developments in different neighborhoods. Essentially, the residents of this area want to keep their large, mature trees, but during storms these trees are uprooting, due to insufficient space to grow along the sidewalks. When a tree is removed, Pepco tops them off and the District removes the tree

Urban Forestry Administration (UFA) staff explained that the UFA owns and is responsible for all street trees along pubic ways. When a tree is removed, a new tree is always planted, in many cases a slow growth tree. The last 2 planting seasons (November thru April), the UFA has planted 4,000 and 3,700 trees respectively.

We visited portions of feeder 15801 (Potomac road) that run along an abandoned trolley line right of way. The right of way, while accessible, is not only heavily treed but affected by residential encroachment. We witnessed tree clearing being done, as well as remaining tree stumps on Cathedral Avenue.

An inventory of all trees in the Palisades has been completed recently, and an evaluation report is available. They have been much more proactive in removing dead trees.

We also visited briefly Feeder # 14015. Pepco staff took us to Urell Street to see established, low growth trees, to demonstrate one option to large trees. These trees (sugarberrys) had been planted 5-10 years ago, but only now were reaching the height of OH lines, and had recently been trimmed for the first time. In many cases these smaller trees are planted in groups of 3, and closer together, to make up for their lack of height.

We attempted to find mapped outages in this area but were unsuccessful.

Costs

$4,000 to remove a large tree

$500 or more to grind stump

$1,000 /day for crane

Wednesday, June 25, 2009 – PSC Washington DC Project

Meeting Location: **Select** 3400 Benning Road, NE, Washington DC 20019

Edison Place 701 Ninth St. NW, Washington, DC 20068

Time: 8:00 AM – 9:00 AM

Attendees:

Pepco Personnel	Subject Matter-Role
	Project Manager and Coordinator
	Manager, Reliability Engineering & Analysis
Shaw Global Team	**Role**
Timothy J. O'Brien	Consultant
Dick Yanco	Technical PM

Agenda: To understand Pepco's approach to Reliability Engineering

Discussion:
We met with the manager of Reliability Engineering & Analysis, to discuss Pepco's system planning efforts.

When planning upgrades, Pepco always analyzes the impact that various alternatives to installations and upgrades will have on reliability, as well as economic considerations. If no funding available for UG, then OH is built.

Pepco currently in the middle of a long term project to all 4kV to 13kV, but not many customers on 4kV, so there will not be much improvement in reliability as a result of this project.

Pepco uses tree wire almost exclusively for new installations.

If there are still outages after trees are trimmed, next step is to sectionalize the area.

Feeder 15197 will be replaced with Pre Assembled Cable (PAC)….will be using PAC cable in the Palisades area (area with WPFs). Staff explained that PAC shouldn't be spliced, but in DC every pole has a transformer with at least one customer attached.

They started using motor operated devices (MOD) in 1995.

Many switches tied to multiple feeders

They are trying internet controlled switches in Maryland (switches that talk to each other)

They are seeing URD cable lasting 20 years.

Paper and lead cable lasting 30 years

Feeder lockout is biggest issue in Palisades

In his opinion, the UG of the mainline would provide the biggest increase in reliability (use in our report as reference)

They had an adopt a feeder program in the past. Pepco just started a new program…..one engineer assigned to each problem feeder

They use a thermo graph camera……..looks at WPF for hot spots

Using a truck mounted sensor in Delmarva, senses for stray voltage

Mainline max distance in DC is 10 miles

Thursday, June 25, 2009 – PSC Washington DC Project

Meeting Location: **Select** 3400 Benning Road, NE, Washington DC 20019

Edison Place 701 Ninth St. NW, Washington, DC 20068

Time: 9:00 AM – 11:00 AM

Attendees:

Pepco Personnel	Subject Matter-Role
	Project Manager and Coordinator
	Distribution Engineering, UG conversion cost estimate
Shaw Global Team	**Role**
Timothy J. O'Brien	Consultant
Dick Yanco	Technical PM

Agenda: To break down and understand how the UG conversion estimate was created.

Discussion:

We met with members of the Distribution Engineering staff. They took us through the details of their estimate to UG one feeder in DC. The estimate was a straightforward calculation of cable, conduit and manholes. They assumed that all trees would remain, thereby avoiding the cost of tree removal.

Their first step was to map the existing OH feeder, and then used that to create a map of a replacement UG feeder, including cable, transformer location, and service drops into individual houses. Quantities for different types were combined before entering the quantities into their cost estimating software, instead of entering quantities for different types separately. Because of this, it will be difficult for us to breakdown their estimate for any kind of analysis.

They used the WMIS system for cost estimating, but do not know what unit rates were in WMIS at the time of the estimate. We will need to obtain the unit rates used in WMIS in order to do a cost comparison with R.S. Means.

Create our own estimate, using Timberline/RS Means?

Use Shaw estimators to create an estimate?

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