
**Task Force to Study Moving Overhead
Utility Lines Underground**

Pursuant to SB 653/Ch. 179, 2002

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THE MARYLAND GENERAL ASSEMBLY
ANNAPOLIS, MARYLAND 21401-1991

December 30, 2003

The Honorable Robert L. Ehrlich, Jr.
Governor

The Honorable Thomas V. Mike Miller, Jr.
President of the Senate

The Honorable Michael E. Busch
Speaker of the House

Members of the Maryland General Assembly

Ladies and Gentlemen:

The Task Force to Study Moving Overhead Utility Lines Underground was created pursuant to Chapter 179 of the Laws of 2002 (Senate Bill 653). The task force was charged with making recommendations on how to facilitate and lower the cost of relocating overhead utility lines underground and reporting to the Governor and the General Assembly by December 31, 2003.

The 22-member task force met five times between August and December 2003 and focused primarily on how to facilitate the undergrounding of electric power lines, although consideration was given to undergrounding all wires – including telephone and cable television – that are located overhead. The recommendations represent a broad consensus of the task force membership and are envisioned to be achievable even within the significant budget constraints of the near future.

The task force expresses its appreciation for the time and effort invested by all members.

Sincerely,

A handwritten signature in cursive script that reads "Charles R. Boutin" with a small mark to the right.

Delegate Charles R. Boutin
Chairman

CRB/MM/lc



THE MARYLAND GENERAL ASSEMBLY
ANNAPOLIS, MARYLAND 21401-1991

Task Force to Study Moving Overhead Utility Lines Underground

2003 Interim

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Senator Leonard H. Teitelbaum

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Task Force to Study Moving Overhead Utility Lines Underground

Introduction

Chapter 179 Acts of 2002 established the Task Force to Study Moving Overhead Utility Lines Underground. The task force's primary purpose was to identify ways to facilitate and reduce the costs of moving overhead utility lines underground. The task force began its work in August 2003 and completed its activities in December 2003. This report is the final report of the task force.

The report consists of four sections. The first section is an introduction, the second section provides some background information, the third section describes the activities of the task force, and the fourth section presents the findings and recommendations of the task force. In addition, enclosed with this report are appendices that include information considered by the task force.

Background

Over the past few years, weather-related power outages have been the focus of several inquiries by the Public Service Commission (PSC) and the General Assembly. One of the strategies to make the electric supply and distribution system more storm resistant has been to underground more overhead lines. In fact, since 1969, State law has required that all utilities be located underground in new subdivisions. However, recognizing the continuing, substantial legacy of overhead wires throughout the State, the General Assembly established this task force to study and make recommendations on how to facilitate and lower the costs of placing utility lines underground, as well as to consider how to improve coordination between utilities and municipal corporations for construction projects on or near roadways where undergrounding utilities may be an option.

To place the work of this task force in context, it is important to recognize the work that was conducted as a result of power outages caused by a severe ice storm in January of 1999 and Hurricane Floyd's passage through Maryland the following September. The three main documents that were produced then, and considered by the current task force, are enclosed with this report as follows:

- **Appendix A** – the report of the *Task Force to Ensure Utility Services, May 2000*;
- **Appendix B** – the Exeter report – *Undergrounding Electric Utility Lines in Maryland, December 30, 1999* (prepared by Exeter Associates, a Silver Spring consultant, pursuant to recommendations of the *Task Force to Ensure Utility Services*); and

- **Appendix C** – the report of the *Selective Undergrounding Working Group – Report to the Public Service Commission on the Selective Undergrounding of Electric Transmission and Distribution Plant, February 14, 2000* (pursuant to PSC Order 75823)

Following the two significant weather events of 1999, the Governor appointed the *Task Force to Ensure Utility Services*, which issued its final report in May 2000. (Appendix A). Although the task force report contained several detailed recommendations on actions to be taken – including actions by the Maryland Energy Administration, Department of Natural Resources, Department of the Environment, Department of Transportation, Department of General Services, Department of Business and Economic Development, Department of Management and Budget, Department of Housing and Community Development, and Office of Planning – most of those recommendations were not implemented. One item that was completed and considered was the Exeter report, *Undergrounding Electric Utility Lines in Maryland* (Appendix B), which was completed on behalf of the Maryland Energy Administration and Power Plant Research Program in the Department of Natural Resources, and which was referenced in, and appended to, the task force's final report, as well as the report of the *Selective Undergrounding Working Group*. The principal finding of the Exeter report was that the wholesale undergrounding of overhead electric lines was not viable due to cost, but that selected portions of distribution lines should be prioritized for undergrounding based on: (1) cost; (2) improvement of reliability; and (3) aesthetics and other factors.

The same weather events of 1999 also prompted the PSC to conduct Case No. 8826, *In the Matter of the Investigation into the Preparedness of Maryland Utilities for Responding to Major Outages*, which was a comprehensive review of utilities' readiness to prepare for and respond to major power outages like those caused by those storms. One result of this case was Order 75823, issued in December of 1999, which called for a collaborative process to consider the benefits and detriments of selectively undergrounding segments of the transmission and distribution systems. Pursuant to this order, the *Selective Undergrounding Working Group*, consisting primarily of electric utility representatives, met and submitted a report on February 14, 2000 (Appendix C). In brief, the working group found that:

- the large-scale undergrounding of electric power (and other utility) lines is not a wholesale, viable means of improving reliability;
- the average cost of undergrounding electric power lines is \$900,000 per mile (undergrounding additional telecommunications lines was estimated to cost over \$1 million per mile);
- the useful life of underground cables is shorter than that of overhead lines;
- in a given time period, frequency of outages may be lower for overhead lines; and
- the duration of outages can be two or three times longer for underground cables versus overhead lines.

Overall, the report found that while undergrounding may be desirable for aesthetic or public policy reasons, the impact on reliability is unclear and the costs are substantial.

Task Force Activities

The task force met five times in 2003. During the first meeting the task force went over its charge and set the agenda for the remainder of its meetings. Suggestions for future meetings included obtaining information on what other cities have done regarding undergrounding of utility lines, an overview of the current State and local regulatory schemes, consideration of the financial effect on customers from burying utility lines, and reviewing past reports on the subject. It was made clear to the task force that, since 1969, all new subdivisions must have their utility lines placed underground.

The second meeting of the task force covered several topics and concluded with a tour of undergrounding projects in Annapolis. The task force heard about other jurisdictions' approaches to underground utility lines, which, apart from a handful of discrete projects, essentially consisted of including the "intent to underground all utility lines" in a comprehensive plan. In addition, it was brought to the task force's attention that the State Public Utilities Article – Title 12, Subtitle 3, actually sets forth a clear process for undergrounding overhead utility lines. The task force also discussed Contributions In Aid of Construction (CIAC) and its impact on the cost of undergrounding projects. Under federal law, contributions to utilities for undergrounding projects which are not considered a public benefit are treated as revenue to the utility and are, therefore, taxable. The costs of undergrounding projects are "grossed-up" so that utilities may recover the costs that are incurred as a result of the tax; for this reason, the recovery of these costs is sometimes referred to as a "gross-up" tax. For undergrounding projects that are considered to be for the public benefit, typically those projects along public roads and highways, the gross-up burden does not apply.

Annapolis learned from the City of Frederick's failed attempt to surcharge customers for undergrounding and decided to pay the full cost with no add-on charges to residents or businesses. Initially, Annapolis attempted to have its portion of undergrounding costs for the historic district paid across the entire rate base of the State, but a 1987 ruling by the Court of Special Appeals upheld the Public Service Commission's finding that Annapolis's costs were chargeable only to Annapolis customers and were not eligible for rate base treatment. Ultimately, Annapolis secured sufficient grant monies from the State, and financed the remainder of the cost of undergrounding through the local tax base, to move their projects forward in distinct phases that are still being implemented today.

The task force also learned of some pros and cons of undergrounding. Regarding reliability, underground lines are initially more reliable; however, underground lines do not have as long of a useful life as overhead lines, and it is more difficult to locate and repair a problem that occurs on an underground line. In some cases, simply de-watering trenches in order to conduct the repair work can be difficult. Repair costs are generally higher and more time-consuming for underground lines, and it was noted that there are currently many more miles of directly-buried cables, rather than buried ducts that require much higher up-front investment, but make it easier to repair damaged lines. Buried ducts typically are used under roadways and in urban settings, but not in rural installations. Installation and maintenance of underground transformers presents further cost and safety issues.

During its third meeting, the task force was briefed on the 1999 Exeter report, *Undergrounding Electric Utility Lines in Maryland*. The report focused on how undergrounding might improve reliability during major storms, and, as noted above, concluded that wholesale undergrounding was not viable because of the cost. It was noted by task force members, in regard to one of the report's recommendations concerning pilot projects (Appendix B, pages 10-11), that although utilities may have collected some cost/benefit data since the report, no pilot projects have been undertaken specifically to gather data for a comprehensive analysis of undergrounding projects. Also, it was noted that there are reports delivered annually to the PSC on the status of undergrounding, and the PSC has raised no concerns regarding the undergrounding of facilities throughout the State. In general, the task force was made aware that there was no good news regarding the cost of undergrounding. The average cost to underground was estimated by electric utilities to be \$900,000 per line per mile (consistent with the findings of the *Selective Undergrounding Working Group*) which averages the higher costs in urban areas and the lower costs for rural lines.

The task force also received an overview of the CIAC, or gross-up tax. Electric utility representatives explained that they charge the tax because they must pay State and federal taxes based on the entire cost of an undergrounding project, which is considered new revenue. The tax does not apply to "public benefit undergrounding," and the utility makes the final call on whether a project qualifies. It was the opinion of utility representatives that the decision regarding the applicability of the tax is straightforward and leaves little room for discretionary judgment. It was unknown what portion of the 27.4 percent tax is State and what is federal.

In a brief presentation of a 2001 survey report entitled, *Utility Undergrounding Programs* (produced by Scientech, a consultant that offers the 80-page report for \$1,200 per copy – which the task force did not purchase for consideration), it was noted that the report did not include significant details on funding modes and sources for undergrounding projects, but simply listed as sources to consider: special assessment areas; undergrounding districts; community development block grants; TEA-21 funds; other federal highway funds; and State or local downtown improvement funds. The report did note that methods to reduce construction costs included undergrounding where work was already planned and combining multiple utilities in a single trench. The task force raised concerns regarding the equity of special assessment areas, and it was estimated that older neighborhoods could require 10-15 years of planning and development for comprehensive undergrounding. Overall, task force members agreed that undergrounding is an expensive process and one that requires a lot of cooperation between utilities, governments, and consumers.

Most of the fourth and fifth meetings of the task force concerned developing conclusions and recommendations, and reviewing the final report of the task force. Nevertheless, several items were brought to the task force's attention. As part of any new construction, although the cost-sharing between utilities and developers may vary, the buyer ultimately pays for the cost of the utility infrastructure. If undergrounding is to ensure reliability and safety, there is a strong argument for reflecting those costs in the rates; if undergrounding is for aesthetics then the cost should not be in the rates paid by customers. It was also brought to the task force's attention that there can be collateral damage from undergrounding. For example, third party damage resulting

from any excavation activities is a common occurrence and a major problem for natural gas providers. The same concerns would apply as more overhead utilities are placed underground. Finally, it became apparent to the task force that undergrounding is a complex effort for local governments, and few, if any, local agencies have the expertise to undertake such an effort.

Findings and Recommendations

Because in the past three years little significant change has taken place as relates to undergrounding, the findings of this task force do not differ substantively from those of the *Task Force to Ensure Utility Services*, the Exeter report, or the report of the *Selective Undergrounding Working Group*. In short, the task force finds that:

1. an existing legal framework exists to facilitate undergrounding; no new laws are necessary to facilitate undergrounding projects;
2. in many cases, improved aesthetics is the primary reason to underground overhead utilities;
3. in addition to improving aesthetics, undergrounding can enhance public safety, as well as provide the opportunity to upgrade telecommunications infrastructure;
4. undergrounding remains very expensive – cost is the primary obstacle to the relocation of overhead wires;
5. economies of scale can be realized when undergrounding if all overhead utilities (electric, cable TV, telephone) are relocated at the same time;
6. further savings can be realized if undergrounding is done in connection with planned infrastructure improvements to roadways or other underground utilities;
7. undergrounding, whether for public safety and reliability or for aesthetic reasons, is appropriate and desirable in certain instances;
8. while the frequency of outages may be significantly improved in the short-term, the long-term reliability of undergrounding is more questionable;
9. underground cables are more susceptible to damage during excavation activities; and
10. while underground outages may occur less frequently, they generally take longer to repair.

The task force's recommendations also reflect some of the recommendations made in the previous reports. The task force offers the following recommendations:

Recommendation # 1. The Attorney General should solicit an opinion and clarification from the Internal Revenue Service (IRS) on the applicability of the Contributions in Aid of Construction (gross-up tax).

Although there is conflicting anecdotal information regarding the applicability of the tax, currently, if an undergrounding project is being completed primarily to improve aesthetics, then the gross-up tax is applicable. A utility representative stated that it is their experience that the IRS is unwilling to offer opinions on the applicability of the tax in hypothetical cases. If undergrounding is interpreted generally to be for public safety reasons, and therefore a public

purpose, contribution payments for undergrounding would not be defined as an addition to capital, and not a Contribution In Aid of Construction, and thus not subject to the gross-up tax (typically along roads and highways).

Because the primary obstacle to undergrounding is cost, and because at 27.4 percent of total project cost, (as stated by one utility) the tax represents a significant portion of that cost, the task force believes that any financial relief may permit more of these projects to go forward.

Recommendation #2. The Maryland Department of Planning (MDP) should serve as a clearinghouse to assist local jurisdictions and groups that are interested in undergrounding.

Although current law and regulations provide a framework for implementing an undergrounding plan, there is no place an interested party can go to get comprehensive advice on the most effective and low-cost ways to complete an undergrounding project. If MDP were to solicit information on undergrounding projects from various jurisdictions and utilities, it could provide substantial assistance to those who choose to explore undergrounding in their communities. For example, the City of Annapolis has significant experience that it would be willing to share on its projects that have been undertaken with owners of overhead utilities.

A clearinghouse of information would also, in part, achieve Recommendation #2 from the Exeter report (Appendix B, page 10) regarding data collection on a variety of undergrounding projects. This kind of consolidated information – including model approaches to design/engineering, financing, and innovative construction techniques -- would be invaluable to groups who have no expertise in undergrounding, but are considering undergrounding projects in their own communities.

Recommendation #3. Local governments, State and local highway authorities, MDP, and owners of overhead facilities should identify opportunities for undergrounding in construction and repair planning, and all parties should work closely to coordinate undergrounding activities.

This recommendation applies particularly to public works projects at and around public roadways. While relocating overhead facilities underground can be very costly, it can be done as efficiently as possible when well-coordinated between local governments, owners of overhead facilities, the PSC, other State offices, and contractors. As mentioned in Findings #5 and #6, placing multiple utilities in a single trench, particularly when construction activities may already be planned for other reasons, can reduce overall project costs and, practically speaking, must be done in order to completely remove utility poles that support the electric, cable, and telephone wires. Additionally, because roadway projects are typically considered to be for the public good, these projects are generally not subject to the gross-up tax.

Task force members stressed the need for close communication with all parties involved in an undergrounding project in order to realize a successful outcome.

**Task Force to
Ensure Utility Services**

Final Report

May 2000

**Task Force to Ensure Utility Services
Membership**

Mr. Hal Adkins
Town of Ocean City

Mr. Mark Mona
Mona Energy & Technology

Mr. Frank Bender
Baltimore Gas and Electric

Mr. George Marshall Naul
Town of Chestertown

Senator James DeGrange
Maryland General Assembly

Delegate George Owings, III
Maryland General Assembly

Mr. Robert Grantley
Potomac Electric Power Company

Ms. Carla Pettus
PJM Interconnection, LLC

Mr. James Latimer
Allegheny Power

Ms. Catherine Riley
Maryland Public Service Commission

Mr. Sean Looney
Bell Atlantic

Mr. Scot T. Spencer
Environmental Defense Fund

Mr. Gene Lynch
Office of the Governor

Mr. Richard Wegman
Garvey, Schubert, and Barer

Mr. Roger Lyons
Baltimore Urban League

Task Force to Ensure Utility Services Executive Summary

The Governor appointed the Task Force to Ensure Utility Services in September 1999, in response to the power outages caused by several severe storms affecting Maryland. The creation of this Task Force coincided with the Governor's request that the Public Service Commission (PSC) investigate Maryland public utilities' emergency response and disaster mitigation plans.

While the PSC investigation primarily focused on utilities' preparedness efforts, the work of the Task Force involved examining the degree to which utility, State, and local emergency management officials worked together to prepare for and respond to natural disasters such as Hurricane Floyd. Its primary task was to recommend long-term solutions to (1) shorten the time needed to restore power when outages occur and (2) mitigate the severity of future outages, wastewater treatment plant disruptions, and other related problems encountered as a result of natural disasters.

The Task Force held eleven meetings, including two meetings to receive public input. The Task Force appreciates the insight provided by those who testified at its meetings, including numerous citizens and representatives from various businesses, Maryland public utilities, the Public Service Commission, the Office of People's Counsel, Maryland Department of Natural Resources, Maryland Emergency Management Agency, Maryland Environmental Service, Maryland Department of the Environment, and local and county governments.

Based on the testimony received, the Task Force developed recommendations that, when implemented, will reduce the time required to recover from natural disasters and improve the resiliency of our existing utility systems.¹ The Task Force recommendations are in two sections: recovery and resiliency. The first section recommends actions utility and emergency management officials should take to improve their ability to respond to major storm events and reduce the time required to restore power. The second section outlines measures that will enhance the resiliency of our systems over the long-term.

The recommendations developed by the Task Force complement the findings and determinations of the Public Service Commission in Case No. 8826, *In The Matter Of The Investigation Into The Preparedness Of Maryland Utilities For Responding To Major Outages*. Accordingly, recommendations of the Task Force should be implemented in conjunction with the PSC's ongoing work.

¹Due to her position as a member of the Public Service Commission, Catherine Riley abstained from voting on the recommendations contained in the final report of the Task Force.

Task Force to Ensure Utility Services Recovery Recommendations

- (1) Maryland Emergency Management Agency (MEMA) should conduct extreme emergency preparedness simulation training sessions. These sessions should simulate the effects of extreme weather conditions in at least two geographic areas of the State (e.g., extreme flooding on the Eastern Shore or one million people without power in suburban Maryland).
- (2) MEMA should convene utility representatives, local emergency management officials, and 911 operators to develop a more effective system for communicating incidents.
- (3) Utilities should accelerate the development and deployment, where possible, of a standard electronic map data base that accepts direct data input from 911 systems, in addition to keyed information with the ability to report by standard geographic units. Such a data base should contain Geographical Information System (GIS) coordinates of critical facilities identified by utility and emergency management officials.
- (4) Where feasible, Maryland 911 systems should develop and deploy the ability to electronically transmit incident reports to electric and gas utility storm centers. In the interim, an appropriate version of the Allegheny Power 911 standard information form should be adopted by all electric and gas utilities.
- (5) In cooperation with local emergency management and utility officials, MEMA should develop prioritized resource asset lists to be distributed to all utilities. In addition, MEMA and utility officials should develop a system to deploy these assets during major storm events.
- (6) Electric and gas utilities that do not automatically identify callers as having special needs should deploy special override numbers or other communication protocols to provide special needs customers with priority service. The Baltimore Gas and Electric (BGE) "209" number system is an example of this type of program.
- (7) Local emergency response agencies, in collaboration with the electric and gas utilities, should develop back-up options (e.g., generators/transportation) for medically at-risk customers. The utilities and the local emergency response agencies should communicate these options to the customers, with local emergency response agencies responsible for the provision of emergency services.
- (8) All electric and gas utilities should deploy interactive voice response systems, similar in capability to the Allegheny Power system, to provide customers with as accurate as possible

power restoration times. Technical developments, such as automatic data conversion of account addresses with phone numbers or electronic alarm technology adaptation, will advance such response systems. Adequate numbers of properly trained and equipped field staff are essential to the success of such a system in large-scale emergencies.

- (9) The Public Service Commission (PSC) should develop a method to compare and evaluate utility performance in service restoration operations (see PSC Order 75823).
- (10) Utility officials and the Maryland Department of Transportation (MDOT) should work together to explore the adoption of an emergency hours restriction procedure similar to Delaware's procedure.

Task Force to Ensure Utility Services Resiliency Recommendations

- (1) The PSC staff, the Department of Natural Resources (DNR), the Maryland Office of Planning (MOP), and the utilities should jointly develop a systematic approach to routine tree trimming on both public rights-of-way and private property. The goal of this effort is to improve the reliability of overhead lines. Toward this end, existing and alternate trimming guidelines and cycle times should be compared and evaluated. In addition, DNR and MOP should publish planting guidelines for public rights of way and pursue their adoption by local governments.
- (2) The utilities should develop and enforce more robust easement agreements to address rear lot line access and tree trimming standards. Additionally, the utilities should develop an education campaign to inform the public of (a) the importance of routine tree trimming and (b) the location and existence of underground utility lines. Increasing public awareness about these issues will help improve utility system reliability.
- (3) Where they contribute to resiliency, the deployment of automated reclosers, such as those used by PEPCO and BGE, or other similar-purpose technology should be accelerated.
- (4) The Maryland Department of the Environment (MDE) should examine current regulations with the intent of prohibiting sewage pumping facilities that do not have access to emergency power back-up with sufficient fuel resources.
- (5) Storm water diversion designs should be included in all new or retrofitted sewer line projects, particularly where topography prohibits flood mitigation storage systems.
- (6) Undergrounding selected portions of the above ground electric distribution system is expensive, but it will reduce the impact of major storms. New development has enjoyed the benefit of underground feeder lines since 1969. Undergrounding is not intended to, nor necessarily will it, improve general (non-storm related) reliability. The undergrounding of the most vulnerable parts of the overhead system should be explored to protect the public health, safety, and welfare. A multi-part phased approach is recommended. Utilities must receive timely recovery of all their costs of undergrounding in order for a significant program to succeed.

During Calendar Year 2000:

- (a) The Maryland Energy Administration (MEA), in cooperation with the Office of the Attorney General, should determine and pursue State and/or federal action needed to eliminate the federal "gross-up" tax on non-utility funded undergrounding.

- (b) The Task Force encourages the careful adoption of a protocol to prioritize undergrounding opportunities. State agencies should proactively cooperate with the utilities and the PSC on this endeavor (see PSC Record of Decision (I): Undergrounding Electric Transmission and Distribution Plant).
 - (c) MDOT, the Department of General Services (DGS), and MEA should identify and use three existing and ongoing undergrounding projects in different parts of the State to detail costs and benefits and describe standards needed to complement the work program recommended in item 6(b) above.
- (7) By January 2001, the Task Force recommends that a three-part funding system for the undergrounding of selected segments of the above ground electric distribution system should be ready to implement.
- (a) The cost of addressing the undergrounding priorities in recommendation 6(b) should be borne by:
 - 1. State government
 - 2. Local government
 - 3. Utilities
 - (b) MEA should work with the utilities, OPC and PSC staff to make recommendations to the PSC concerning how the utilities will recover the costs they will encounter in an undergrounding program in a timely manner.
 - (c) MDOT, the Department of Business and Economic Development, the Department of Housing and Community Development, and DGS should identify locations where other State infrastructure projects provide the opportunity for significant cost reduction for undergrounding projects.

Task Force to Ensure Utility Services Findings and Recommendations

Recovery Recommendations

Recommendation #1

Maryland Emergency Management Agency (MEMA) should conduct extreme emergency preparedness simulation training sessions. These sessions should simulate the effects of extreme weather conditions in at least two geographic areas of the State (e.g., extreme flooding on the Eastern Shore or one million people without power in suburban Maryland).

Long-range weather forecasts by the National Weather Service Prediction Center indicate that the East Coast is likely to experience increased hurricane and tropical storm activity in the coming years. In light of these forecasts, utility, State, and local emergency management officials should take additional steps to prepare to respond to these major storm events.

The Task Force recommends that MEMA conduct extreme emergency weather preparedness training sessions. Additionally, MEMA should explore a partnership agreement with Johns Hopkins University (JHU) to use JHU's existing assets to further the effectiveness of these training exercises. The Task Force believes such training sessions would improve the readiness and capability of the public and private sectors to respond efficiently and effectively to a variety of large-scale storm events throughout the State.

These sessions should, at a minimum, be attended by representatives of all utility, State and local emergency management agencies. Such training sessions should supplement any emergency training sessions currently conducted by MEMA, other government agencies, and the utilities.

Recommendation #2

MEMA should convene utility representatives, local emergency management officials, and 911 operators to develop a more effective system for communicating incidents.

The Task Force received testimony from utility officials that a single incident may generate more than 37 phone calls from individuals, 911 call centers, and local fire and police stations. Further, the Task Force learned that when a single incident generates multiple incident reports, the utilities must sort through inaccurate or conflicting information before dispatching a crew to the scene of the incident. The Task Force also found that restoration efforts were hampered when utilities failed to inform local government agencies after an incident had been handled. For example, if a utility had responded to reports of a downed live wire, it may not automatically inform

the local government when it may safely remove any traffic barricades or other debris.

To address this issue, the Task Force recommends that MEMA work with 911 operators and utility and emergency management officials to develop a more efficient and effective system for communicating and responding to incidents. While the Task Force recognizes that an incident may require a unique response, a system or communication protocol should be developed to ensure that utilities (1) receive accurate and coordinated information about an incident; (2) send a crew to quickly assess the incident; (3) make the scene safe and address any public safety issues; (4) notify the local government that any public safety issues have been addressed; and (5) continue its restoration protocol.

Recommendation #3

Utilities should accelerate development and deployment, where possible, of a standard electronic map data base that accepts direct data input from 911 systems, in addition to keyed information with the ability to report by standard geographic units. Such a data base should contain Geographical Information System (GIS) coordinates of critical facilities identified by utility and emergency management officials.

System restoration efforts start with the ability to receive accurate incident reports. The Task Force received testimony stating that utilities did not always receive complete information regarding the location of an incident. For example, a utility may be notified of a downed wire near an elementary school without being given the school's address. Receiving incomplete information unnecessarily prolongs the utilities' response time and hampers restoration efforts.

To address this issue, the Task Force recommends that the utilities continue to work with emergency management officials to identify the location of all critical facilities within their service territories. The Task Force further recommends that utilities develop and deploy a standard electronic map database that locates critical facilities using Geographic Information System (GIS) technology and that interfaces with local enhanced 911 systems. The use of a common site identification system by all concerned parties will ensure that the utilities receive accurate information about the location of all incidents reported.

Recommendation #4

Where feasible, Maryland 911 systems should develop and deploy the ability to electronically transmit incident reports to electric and gas utility storm centers. In the interim, an appropriate version of the Allegheny Power 911 standard information form should be adopted by all electric and gas utilities.

The Task Force finds that the current system in place to respond to calls from 911 centers is paper and labor intensive. The Task Force is aware that the utilities are moving to upgrade internal and external communication facilities to develop a more seamless flow of information that can be electronically transmitted; these efforts should be applauded.

Officials from Allegheny Power testified that the company provided a standard information form to 911 centers. When the 911 center receives a call, it faxes the information form directly to the utility's storm center. At the storm center, a dedicated fax machine immediately rings to notify dispatchers of the incoming emergency call. While this process does allow for direct communication between the 911 center and the utility's storm center, the Task Force recommends that MD 911 systems develop and deploy technology that allows them to electronically transmit incident reports to the utilities' storm centers. Maryland 911 centers currently have the ability to electronically transmit incident reports to the local fire and police stations. Until this technology is implemented, the Task Force recommends that the utilities adopt an appropriate version of Allegheny Power's system of the standard reporting form and dedicated fax machine.

Recommendation #5

In cooperation with local emergency management and utility officials, MEMA should develop prioritized resource asset lists to be distributed to all utilities. In addition, MEMA and utility officials should develop a system to deploy these assets during major storm events.

The Task Force agrees that in order to maximize restoration efforts, utilities should work with MEMA to develop a coordinated system of resource asset management (e.g., assets such as trucks or tree-removal equipment). In cooperation with local emergency management and utility officials, MEMA should develop resource asset lists that are distributed to all utilities. MEMA should update the availability status of these resources on a regular basis so that the utilities can quickly procure and deploy necessary resources during major storm events. With more extreme weather conditions forecasted, more extensive use of emergency management and other State and local resources may be required.

Recommendation #6

Electric and gas utilities that do not automatically identify callers as having special needs should deploy special override numbers or other communication protocols to provide special needs customers with priority service. The Baltimore Gas and Electric (BGE) "209" number system is an example of this type of program.

During severe storms, crew dispatchers at the public utilities often cannot handle the increased volume of emergency calls. The Task Force recognizes that the utilities have initiated

efforts to address these issues. For example, BGE and PEPCO have deployed more robust communication systems and have enhanced personnel training efforts. BGE also found during Hurricane Floyd that utilizing dedicated phone lines allowed its county representatives located at the local emergency management offices to bypass the general telephone queue and immediately reach a dispatcher. The Task Force supports and applauds the continued improvements to these communication systems.

Customers with special electricity needs due to medical or other critical conditions must be a high priority for all utilities. The Task Force recommends that dedicated phone lines should be used for these customers if the utility's customer service system does not automatically identify callers as having "special needs" (such as Allegheny Power's system, described in Recommendation #8). Customers with medical and other special needs should be able to reach a customer service representative in the event of an outage without experiencing an extended wait.

Recommendation #7

Local emergency response agencies, in collaboration with the electric and gas utilities, should develop back-up options (e.g., generators/transportation) for medically at-risk customers. The utilities and the local emergency response agencies should communicate these options to the customers, with local emergency response agencies responsible for the provision of emergency services.

The Task Force received testimony from several citizens illustrating the medical problems they encounter when extended power outages occur. Some individuals indicated that their medical condition required reliance on energy-consuming medical equipment. Others noted that they suffered serious health risks if exposed to extreme temperatures. While some citizens reported purchasing generators to prepare for power outages, others stated that they lacked the financial resources to purchase such equipment.

Medically at-risk customers should be aware of and have access to back-up options in the event of an outage. The Task Force believes that local emergency response agencies are most able to provide these services in the event of an emergency. With the customer's permission, the utilities should provide local emergency response agencies with updated lists of medically at-risk customers and advise the agencies of the most effective options. Because the utilities have an established customer service relationship mechanism, the utilities should communicate the options to these customers. The local emergency response agencies should provide the services during an emergency.

Recommendation #8

All electric and gas utilities should deploy interactive voice response systems, similar in

capability to the Allegheny Power system, to provide customers with as accurate as possible power restoration times. Technical developments, such as automatic data conversion of account addresses with phone number or electronic alarm technology adaptation, will advance such response systems. Adequate numbers of properly trained and equipped field staff are essential to the success of such a system in large-scale emergencies.

During an outage, it is essential that customers have access to continuously updated information about estimated restoration times and the nature of the outage. Without this information, customers cannot effectively arrange alternate sources of food, shelter and heat if necessary.

Allegheny Power has implemented a model Interactive Voice Recognition (IVR) system that efficiently and accurately provides customers with essential information over the phone. When customers call the service center, the IVR system automatically identifies the address from which the customer is calling by cross referencing the incoming phone number with a database of customer addresses. The system, which is continuously updated, will then automatically notify the caller of critical information such as whether that particular address is part of a larger outage, the estimated time of restoration, and the cause if known. If the customer wishes to report an outage at that address, the system requires only the press of a button. The customer also has the option of reporting outages at other addresses using an account number or phone number if the account number is unknown.

The Allegheny system allows the company to provide service updates to customers quickly, accurately, and efficiently. According to Allegheny, 50 to 55 percent of customers who call the company during a major storm to report outages use the automated system, thus freeing customer service representatives to handle more complex reports. With the IVR system, Allegheny's customer service center can handle 14,000 calls per hour. The company also has contracted with a service bureau, which uses an IVR system that mirrors the Allegheny Power system, to handle overflow calls at a rate of 20,000 calls per hour, with its own overflow capability of up to 100,000.

System automation has allowed Allegheny to develop new and innovative ways to serve its customers. In the future, the IVR system will automatically call customers to confirm restoration. A customer will only have to answer "yes" or "no" for the computer to register the information. If the answer is "no," the IVR will automatically print a new trouble ticket. Customers with a medical need for electricity will also receive enhanced service in the future. These customers will receive a call when an estimated time of restoration has been determined or has changed to confirm that service is operational.

The Task Force recognizes that IVR systems such as Allegheny's take time to develop and implement and that Pepco, BGE, Connectiv, and SMECO are in various stages of developing such systems. However, given the serious hardship that can result from prolonged service outages, the rapid deployment of such systems is essential. It is critical that customers receive accurate and timely information about restoration times so they can take steps to avoid serious harm. Therefore,

all utilities should endeavor to deploy IVR systems that are similar to or more robust than the Allegheny Power system.

Recommendation #9

The Public Service Commission (PSC) should develop a method to compare and evaluate utility performance in service restoration operations (see PSC Order 75823).

In its December 1999 report on the utilities' response to recent outages, the PSC recognized its authority to adopt operation and performance standards and established a Working Group to further explore the development of such standards. The Task Force agrees that the PSC should continue its efforts to develop restoration performance standards for public utilities.

All utilities are vulnerable to system failures. Considering that more than 50% of utility customers are served by overhead power systems, these systems will continue to remain vulnerable to downed trees and the effects of major storms. To respond to these emergency situations, utilities employ a variety of strategies; there is no "single" strategy applicable to all situations. The Task Force believes that a common set of performance indicators must be developed to determine the effectiveness of the various strategies a utility may use to respond to emergency situations. As utilities move to a deregulated environment, developing such performance indicators becomes even more important.

Recommendation #10

Utility officials and the Maryland Department of Transportation (MDOT) should work together to explore the adoption of an emergency hours restriction procedure similar to Delaware's procedure.

State and federal law restrict the number of service hours for commercially-licensed drivers. Federal regulations also require drivers to maintain a log book of activities and hours driven. Intrastate drivers traveling exclusively within Maryland and only within a 100 mile radius do not have to comply with the additional federal regulations; interstate drivers, however, must comply with both Maryland and federal law. The utilities testified that the hours-of-service restrictions hamper their ability to restore utility services after an outage occurs.

Two mechanisms may be employed to exempt utilities from the hours-of-service restriction in Maryland:

- (1) Utilities may apply to MDOT for an exemption. The Maryland Secretary of Transportation may waive the maximum hours-of-service time restrictions for all interstate and intrastate drivers who provide direct assistance in restoring utility services when a declared utility or transportation emergency exists. The utilities contend that requesting an exemption is

burdensome. Additionally, they noted that the exemption is valid only for one days; after each day, another request must be made.

- (2) The Governor may waive the hours-of-service restrictions by declaring a State of Emergency. The utilities noted that although a storm may not be of the magnitude to declare a State of Emergency, it may cause sufficient damage to justify the utilities' request for a waiver from the hours of service restrictions.

In response to these concerns, the Task Force recommends that utility representatives and MDOT explore the adoption of a policy that meets the dual purpose of (1) protecting Maryland citizens from the elevated risk associated with commercially-licensed drivers working extended hours on Maryland's roadways and (2) granting flexibility to utility line crews and drivers so that restoration times may be reduced. The Task Force recommends that MDOT and utility officials consider Delaware's policy. Although a utility must apply for a waiver in Delaware, the waivers granted are valid for the duration of the emergency or until rescinded; a utility does not have to reapply for a waiver after each day.

**Task Force to Ensure Utility Services
Findings and Recommendations
Resiliency Recommendations**

Recommendation #1

The PSC staff, the Department of Natural Resources (DNR), the Maryland Office of Planning (MOP), and the utilities, should jointly develop a systematic approach to routine tree trimming on both public rights-of-way and private property. The goal of this effort is to improve the reliability of overhead lines. Toward this end, existing and alternate trimming guidelines and cycle times should be compared and evaluated. In addition, DNR and MOP should publish planting guidelines for public rights of way and pursue their adoption by local governments.

Routine tree trimming cycles are intended to prevent limbs from coming in contact with overhead utility lines and creating an outage in the electric circuit. Regulations adopted pursuant to the Maryland Roadside Tree Law, applicable to trees in public rights of way, require that roadside trees trimmed to maintain clearance for utility wires allow sufficient clearance for two years of growth. The utilities expressed concern that current laws and regulations governing tree trimming cycles impede their ability to effectively manage vegetation growth and therefore minimize power disruptions caused by downed trees or limbs. The utilities also suggested that specifications should be established to limit plantings near overhead utility lines to low-growing shrubs and trees.

DNR noted that the Maryland Roadside Tree Law is meant to encourage utilities to trim trees frequently, thereby safeguarding tree health and appearance by not cutting too deeply into old growth. DNR stated that deep cuttings cause trees to produce small suckers that grow quickly and are weaker than normal branches, thus increasing the likelihood of damaging overhead power lines.

Additionally, DNR noted that the Maryland Roadside Tree Law applies only to trees along public rights-of-way; it does not apply to trees that may overhang a utility line or are on private property with rear power lines. On private property, tree trimming is performed by or is under the supervision of tree experts licensed by DNR. As a result, unless permitted by a right-of-way agreement, utilities must obtain owner approval before trimming trees on private property. The utilities noted that property owners often resist utilities' efforts to trim trees or overhanging branches that pose a risk to overhead lines.

In light of these issues, the Task Force recommends that a systematic process for trimming trees on both public rights of way and private property be developed. This process should be developed in coordination with the staff of the PSC, DNR, MOP, and the utilities. Such coordination will ensure that the process developed addresses the need to minimize power

disruptions caused by downed trees, while also considering the ecological, social, economic, and aesthetic value of trees.

The Task Force is also aware that the types of trees planted near overhead utility lines directly affects system reliability and utilities' vegetation management costs. Although many local jurisdictions require developers to select from a "plant species" list when planting vegetation in public rights of way or following local landscape requirements, the Task Force is concerned that these lists do not specify the appropriate types of vegetation that should be planted under and around utility lines. For example, these lists do not preclude developers from planting tall or structurally weaker trees in and around utility lines. Such trees, if overhanging utility lines, may pose significant reliability risks to the overhead distribution system.

To address these concerns, the Task Force recommends that DNR and MOP work with local governments to encourage them to establish and enforce planting guidelines. Such guidelines should encourage the planting of vegetation most appropriate near overhead utility lines. The Task Force further recommends that DNR continue to educate local governments about the importance of enforcing the Maryland Roadside Tree Law and the potential problems trees pose to overhead lines when reviewing local master plans for compliance with the State Forest Conservation Act.

Recommendation #2

The utilities should develop and enforce more robust easement agreements to address rear lot line access and tree trimming standards. Additionally, the utilities should develop an education campaign to inform the public of (a) the importance of routine tree trimming and (b) the location and existence of underground utility lines. Increasing public awareness about these issues will help improve utility system reliability.

Prior to 1969, utilities were not required to bury new electric and telephone distribution lines underground. As a result, significant portions of the utilities' overhead distribution lines are situated on private property. Utilities' access to these lines is limited by easement agreements between the utility and the property owner. The utilities stated that property owners often resist utilities' efforts to trim trees or overhanging branches that pose a risk to the distribution line.

To address the concerns of both the utilities and the property owners, the Task Force recommends that utilities work with property owners to strengthen and enforce existing easement agreements. Additionally, the Task Force recommends that the utilities develop a public education campaign to enhance the public's understanding of the importance of routine tree trimming. By educating citizens about how they plan to manage vegetation growth around overhead lines and the importance of doing so, utilities can enhance the overall vegetation management process.

The Task Force noted that although underground lines are not vulnerable to tree damage, property owners may cause power disruptions by inadvertently digging or excavating around

underground lines. State law does require individuals to notify Miss Utility, a utility-sponsored service that verifies the location of underground lines, before they begin excavating an area. The Task Force recommends that the utilities continue to work to increase the public's awareness about the location of underground lines. For example, utilities could distribute information to new homeowners about the location of underground utility lines on their property.

Recommendation #3

Where they contribute to resiliency, the deployment of automated reclosers, such as those used by PEPCO and BGE, or other similar-purpose technology should be accelerated.

Distribution automation systems allow utilities to limit the effects and duration of unplanned outages. While devices such as automated reclosers do not prevent outages, they can minimize the severity of outages by isolating faults on distribution lines and rerouting power around the faults in networked or looped systems with sufficient load bearing capacity. PEPCO, for example, has initiated a program to install motor operated disconnects on overhead distribution lines in neighborhoods experiencing a high degree of power disruptions.

The Task Force applauds the utilities' efforts to deploy such devices. BGE noted, for example, that it has installed automated reclosers on approximately 10 percent of its overhead 13 kV distribution lines. The Task Force recommends that utilities accelerate the deployment of such technology to further improve the reliability of the existing overhead electric distribution system.

Recommendation #4

The Maryland Department of the Environment (MDE) should examine current regulations with the intent of prohibiting sewage pumping facilities that do not have access to emergency power back-up with sufficient fuel resources.

MDE's current "Design Guidelines for Sewerage Facilities" require a dual power source for pump stations serving more than 50 single-family dwelling units. For those stations not required to have a dual power source, MDE requires that a "reserve storage" for raw sewerage be provided. Although the amount of storage volume required for these stations is based on projected flows and power outage history, required storage levels may not be adequate to handle the raw sewerage overflows that could occur as a result of the extended outages.

The Task Force recommends that MDE reexamine its current regulations to require that all sewage pumping stations have access to adequate emergency power back-up. The emergency power back-up options developed for the station should ensure that sufficient fuel resources are available to handle extended power outages.

Recommendation #5

Storm water diversion designs should be included in all new or retrofitted sewer line projects, particularly where topography prohibits flood mitigation storage systems.

The Task Force heard testimony from the Maryland Environmental Service (MES) that the volume of storm water entering sewage lines during Hurricane Floyd rendered several waste water treatment facilities inoperable. To address this issue, the Task Force recommends that new or retrofitted sewer line projects incorporate storm water diversion designs. Such designs or structures could include:

- Installation of manhole rain shields;
- Correction of leaking laterals or building connections;
- Disconnection of the roof leaders to the sewerage systems;
- Elimination of prohibited connections such as basement sump pumps, drains for storm water runoff, or building foundation drains;
- The repair of leaking sewer pipes and manhole joints; or
- The reduction of pipe joints within new sewerage systems.

The Task Force anticipates that incorporating these designs into new or retrofit projects will reduce the amount of storm water entering a sewerage system, thereby reducing the likelihood that these systems will experience flooding during major storm events.

Recommendation #6

Undergrounding selected portions of the above ground electric distribution system is expensive, but it will reduce the impact of major storms. New development has enjoyed the benefit of underground feeder lines since 1969. Undergrounding is not intended to, nor necessarily will it, improve general (non-storm related) reliability. The undergrounding of the most vulnerable parts of the overhead system should be explored to protect the public health, safety, and welfare. A multi-part phased approach is recommended. Utilities must receive timely recovery of all their costs of undergrounding in order for a significant program to succeed.

During Calendar Year 2000:

- (a) *The Maryland Energy Administration (MEA), in cooperation with the Office of the Attorney General, should determine and pursue State and/or federal action needed to eliminate the federal "gross-up" tax on non-utility funded undergrounding.*
- (b) *The Task Force encourages the careful adoption of a protocol to prioritize*

undergrounding opportunities. State agencies should proactively cooperate with the utilities and the PSC on this endeavor (see PSC Record of Decision (I): Undergrounding Electric Transmission and Distribution Plants).

- (c) *MDOT, the Department of General Services (DGS), and MEA should identify and use three existing and ongoing undergrounding projects in different parts of the State to detail costs and benefits and describe standards needed to complement the work program recommended in item 6(b) above.*

Representatives from Exeter Associates, Inc., a private consulting firm, presented findings from its feasibility study on undergrounding electric utility lines (see Appendix A). Exeter's study highlighted the advantages and disadvantages of both overhead and underground systems. The study noted that overhead systems cost less to install and are easier to upgrade, repair, and replace than underground systems. Overhead systems, on the other hand, are not aesthetically pleasing. Such systems also experience damage from wind, ice, vehicles, and trees and thus pose a substantial risk to the public health and safety. In contrast, Exeter noted that while underground systems are not affected by wind, ice, vehicles or trees, these systems may experience power failures if flooding occurs or if insulation layers deteriorate or suffer rodent damage. Exeter also explained that the costs of undergrounding vary based on location. For example, undergrounding lines in highly urbanized areas would require removing and replacing pavements. Similarly, the dense root structure of heavily wooded areas would require more time-consuming and expensive operations, such as directional boring.

The financial costs of undergrounding should be balanced against the costs businesses and individuals incur as a result of extended power outages. Emory Harrison, Director of Central Services for the City of Annapolis, Department of Public Works, noted that local businesses and residents should support undergrounding projects since undergrounding would improve system reliability during major storm events such as Hurricane Floyd.

The Task Force notes that in 1969, the PSC determined that it was in the interest of public health and safety to require all new low-voltage electric and telephone distribution lines be buried underground. While cognizant of the advantages and disadvantages of underground distribution systems, the Task Force believes that it is in the public interest to explore the selective undergrounding of the most vulnerable parts of the existing overhead distribution system, e.g., older neighborhoods experiencing frequent and prolonged power outages. Determining which segments should be considered first for undergrounding should be based on a physical assessment protocol and the judgment of the funding partners.

To better estimate the costs and benefits of undergrounding portions of the overhead system, the Task Force recommends that MDOT, MEA, and DGS examine three existing and ongoing undergrounding projects in Maryland. Three project sites have been tentatively identified: Garrett Park, Ocean City, and Annapolis. The Task Force anticipates that an analysis of these projects will assist the PSC and other State agencies in developing the protocol for determining which portions of the overhead system should be eligible for undergrounding.

Since its 1969 determination, the PSC has permitted the utilities to recover through the rate structure the cost of undergrounding all new low-voltage electric and telephone distribution lines. The Task Force believes that if selected segments of the existing overhead transmission and distribution lines are placed underground, the utilities should be able to recover their costs in a timely manner. Equity and public safety require this approach.

To further reduce the cost of undergrounding existing overhead systems, the Task Force recommends that MEA and the Office of the Attorney General pursue changes to eliminate the federal "gross-up" tax on non-utility funded undergrounding projects. Some interpretations of the Federal tax law changes of 1986 hold that payments a utility receives from a government for undergrounding existing overhead distribution systems are operating income, not an addition to capital. The Task Force believes that for public safety reasons, undergrounding is a public purpose. The funding structure recommended is not a Contribution in Aid of Construction (CIAC) by the proximate beneficiary. A more accurate reading of Federal tax law will treat such payments as an addition to capital and thus not subject to a "gross-up" tax.

Recommendation #7

By January 2001, the Task Force recommends that a three-part funding system for the undergrounding of selected segments of the above ground electric distribution system should be ready to implement.

- (a) The cost of addressing the undergrounding priorities in recommendation 6(b) should be borne by:
 - 1. State government
 - 2. Local government
 - 3. Utilities*

- (b) MEA should work with utilities, OPC and PSC staff to make recommendations to the PSC concerning how the utilities will recover the costs they will encounter in an undergrounding program in a timely manner.*

- (c) MDOT, the Department of Business and Economic Development, the Department of Housing and Community Development, and DGS should identify locations where other State infrastructure projects provide the opportunity for significant cost reduction for undergrounding projects.*

The Task Force anticipates that the cost of any undergrounding project could not be borne by a single entity. As a result, the Task Force recommends that MEA, in conjunction with MDOT, the PSC, and the Department of Budget and Management (DBM), develop a funding strategy to spread project costs among those benefitting from undergrounding projects. This strategy should

consider the funding role of State and local governments and utilities. Spreading project costs among these entities should make project costs more reasonable to bear. While not adaptable in total, the urban districts of Montgomery County are good examples of this approach. Contributions of those directly benefitting may need to be excluded so as to avoid violating IRS interpretations of the 1986 Tax Act.

The Task Force anticipates that this funding strategy will be developed by January 2001. Since undergrounding projects identified through the protocol established in Recommendation 6 will likely involve a State commitment of funds, this timeframe will ensure that funding for these projects can be considered by the General Assembly during the 2001 legislative session.

To assist utilities in recovering their undergrounding costs, the Task Force encourages MEA to work with the utilities, OPC and PSC staff to develop recommendations for consideration by the PSC. As stated in Recommendation 6, the Task Force recommends that all costs incurred by the utilities for undergrounding selected portions of the existing overhead system be recovered in a timely manner.

The cost of undergrounding projects can be reduced significantly if the project is coupled with other infrastructure projects (e.g., gas line or storm water tunnel upgrades, laying of fiber optic cables). This arrangement spreads the initial costs of demolition, excavation, restoration, and pavement laying among numerous funding sources. The Task Force recommends that, as undergrounding project sites are identified using the protocol established in Recommendation 6, MOP coordinate with MDOT, the Department of Business and Economic Development, the Department of Housing and Community Development, DGS, and local government planning offices to determine if other State or local construction projects or private resource sharing agreements could be coupled with planned undergrounding projects.

**UNDERGROUNDING ELECTRIC UTILITY
LINES IN MARYLAND**

PREPARED FOR:

**MARYLAND ENERGY ADMINISTRATION
AND THE
POWER PLANT RESEARCH PROGRAM**

DECEMBER 30, 1999

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Executive Summary

The Governor's Task Force on Utility Preparedness requested an assessment of issues related to converting existing overhead (OH) electric utility lines to underground (UG) lines. The fundamental questions addressed herein are whether undergrounding electric utility lines is a feasible means to reduce the likelihood of future severe and widespread electric power outages similar to the 1999 outages occurring as a result of the January ice storm and Hurricane Floyd in September, and to reduce service restoration times following severe and widespread outages. The analysis performed was limited to the Baltimore Gas and Electric Company (BGE) and the Potomac Electric Power Company (PEPCO), since these were the Maryland utilities most affected during the extreme weather conditions of 1999. To perform the assessment, relevant documents were reviewed, interviews conducted, portions of the utilities' sub-transmission and distribution systems were inspected, and site visits were made to the utilities' control centers.

The key findings, conclusions, and recommendations resulting from this analysis are as follows:

Findings and Conclusions

1. The utilities' transmission systems, sub-transmission systems, and substations were largely unaffected by the ice storm and Hurricane Floyd and significant restoration efforts for these system components were not required.
2. Almost all of the restoration efforts related to the ice storm and Hurricane Floyd were directed toward distribution mains, distribution laterals from mains, secondary conductors, and service conductors directly connecting end-users.
3. Relative to overhead lines, underground lines offer advantages in terms of aesthetics; reduced susceptibility to damage from wind, ice, and vehicles; reduced operation and maintenance costs; and minimization of inadvertent contact with lines by people and animals.
4. Relative to overhead lines, underground lines present disadvantages in terms of installation costs; power-carrying capacity; the ease (and cost) of locating and correcting problems on the lines; the ease of performing system upgrades; and certain ancillary concerns such as traffic disruption during installation, arranging for placement of above-ground transformers on private property, and possible impacts on other above-ground utility systems, e.g., telephone and cable television.
5. Assuming an average cost per mile of \$450,000 for undergrounding the existing OH distribution systems of PEPCO and BGE, the cost of undergrounding would result in substantial increases in electric utility rates if funding for undergrounding were to be collected fully from distribution service ratepayers. Increases in residential rates are estimated to be approximately 36 percent for BGE customers (or an increase of approximately \$340 per year) and 46 percent for PEPCO customers (or an increase of approximately \$415 per year).
6. Costs for undergrounding existing overhead lines vary significantly depending on the specific characteristics of the area, such as topography, geology, and land use.
7. Completion of conversion to UG lines for substantial portions of the OH distribution system will likely require 15 to 20 years for planning, design, and construction.

Recommendations

1. Conversion of the entire aerial distribution systems of the Maryland utilities does not appear to be viable based on installation costs.

2. Undergrounding for selected portions of the utilities' distribution systems should be adopted, with prioritization established based on cost, impact on improved reliability, and ancillary considerations (e.g., aesthetics, traffic impacts).

3. A pilot program should be adopted wherein each utility would identify four to five different areas, each requiring different types of underground construction. Costs and other relevant factors should be carefully tracked to enable development of a full and comprehensive analysis of undergrounding issues. Among the items to be monitored and tracked in addition to installation costs are: impacts on other OH utility systems; difficulties that may be encountered with obtaining permission for placement of above-ground transformers; traffic disruption; reliability improvements; and qualitative assessments regarding improved access for emergency equipment (e.g., fire trucks), aesthetic considerations, and reduced requirements for tree trimming and vegetation management.

To the extent that utilities have performed recent conversion of OH lines to UG, the pilot program need not require additional conversion if accurate cost data are available and other desirable data and information from the project can be reconstructed or monitored.

4. Additional research should be conducted on the impacts of undergrounding electric utility lines on other OH utility systems.

5. Several funding methods for undergrounding existing OH distribution lines were identified, including:

- a. State funding;
- b. local government funding;
- c. ratepayer funding;
- d. funding from those customers receiving direct benefit; and
- e. funding from other conduit users providing communication services.

The wide range of benefits associated with undergrounding select portions of the electric utilities' distribution systems suggests a broad funding mechanism is appropriate. A combination of the potential funding sources appears warranted and it is recommended that a funding approach be developed for those portions of the electric distribution systems that have the greatest effect on reliability.

6. Tree trimming and vegetation management practices should be reviewed to ensure balance between utility distribution system reliability with other legitimate policy objectives.

1. Introduction and Background

1.1 Purpose of Analysis

In January 1999, portions of the service areas of the Baltimore Gas and Electric Company (BGE) and the Potomac Electric Power Company (PEPCO) experienced prolonged electric power outages resulting from a severe ice storm. In September of 1999, additional electric power outages were experienced by BGE and PEPCO customers from distribution system damage caused by Hurricane Floyd. The scale of these outages, coupled with long restoration times which left some electric customers without power for five days, prompted the establishment of a Governor's Task Force to examine methods that could be employed by Maryland utilities to reduce the likelihood of future widespread outages of long duration associated with severe weather occurrences. This report focuses on one area addressed by the Governor's Task Force on Utility Preparedness (Task Force): the potential benefit and viability of converting overhead electric distribution facilities to underground facilities. Converting distribution facilities to underground would reduce the exposure of the distribution system to wind, ice, and fallen trees and tree limbs.

During the course of the investigation, other ancillary, but related, issues arose which are addressed briefly in this report. These issues include vegetation management practices and outage reporting.

Findings and recommendations are presented in the concluding section of this report. Also noted are issues requiring additional research which were beyond the scope of this investigation or were unable to be fully addressed during the abbreviated investigation schedule.

1.2 Scope of Investigation

During the course of the investigation, numerous documents were reviewed, interviews conducted, and facilities inspected. This subsection identifies the source information relied upon which forms the basis of the findings, conclusions, and recommendations.

1.2.1 Documents

The documents, records, and written material reviewed in connection with this investigation were obtained from several sources including Maryland State government offices, BGE, and PEPCO. Additionally, other publicly available information was relied upon. The primary documents and records relied upon are summarized below:

- Outage records;
- Maryland Public Service Commission hearings transcripts and supporting documents (Case No. 8826) and Commission Order No. 75823;
- Transmission and distribution system maps;

- Documents related to restoration efforts for outages from the January ice storm and Hurricane Floyd;
- Federal Energy Regulatory Commission Form No. 1 data; and
- Popular press and trade publication articles.

1.2.2 Interviews and Meetings

In addition to review of documents, meetings and interviews of utility company personnel were conducted to help in understanding the circumstances surrounding the 1999 outages, the methods by which restoration of services was performed, and factors potentially affecting system reliability in the future. A list of the meetings conducted and the personnel interviewed is contained in an appendix to this report.

1.2.3 Facilities Inspected

Portions of the BGE and PEPCO sub-transmission and distribution systems, as well as certain other utility facilities, were visually inspected. The facilities inspected/visited included:

- | | | |
|-------|---|---|
| BGE | - | South Anne Arundel County sub-transmission and distribution lines |
| | | Portions of the sub-transmission and distribution system in Baltimore County and Baltimore City |
| | | BGE's Control Center |
| PEPCO | - | BGE's Call Center |
| | | Portions of PEPCO's sub-transmission and distribution systems in Prince Georges and Montgomery Counties |
| | | PEPCO's Control Center |

1.3 General Description of BGE and PEPCO Systems

To provide a framework for the remainder of this report, this subsection presents an overview of the BGE and PEPCO sub-transmission and distribution systems. Electric power generating facilities (power plants) and the transmission systems (i.e., 115 kV and above, used for bulk power transmission) are not discussed since undergrounding is irrelevant for generating stations and the transmission system of neither BGE nor PEPCO was affected by the severe weather occurrences in 1999. Additionally, transmission line is generally restricted to overhead for economic reasons.

The subtransmission and distributions systems for both BGE and PEPCO consist of:

- Subtransmission (Feeder) - 69 kV and 34.5 kV for source to distribution substations;

- Distribution Substations - 69 kV or 34.5 kV to 4.16 kV or 13.2 kV;
- Distribution Mains - 4.16 kV, 3-phase or 13.2 kV, 3-phase;
- Distribution Laterals from Mains - Single-phase or 3-phase 4.16 kV or 13.2 kV;
- Distribution Transformers - 4.16 kV or 13.2 kV to utilization voltage, 120/208 V, 120/240 V, or 277/480 V;
- Secondary Conductors - Common bus for each utilization voltage;
- Service Conductors to User - Conductors from secondary conductors to user's meters.

The subtransmission lines have remotely controlled and/or manually operated sectionalizing devices to form looped systems. The distribution lines in densely populated areas are looped systems with sectionalizing devices for isolating sections of damaged lines to facilitate line repair. Distribution lines in sparsely populated areas are generally lateral feeds with no looped service for redundant supply.

2. Underground Versus Overhead Lines -- Advantages and Disadvantages

2.1 Introduction

While underground (UG) lines offer several important advantages over overhead (OH) lines, there are also disadvantages relative to OH lines. The advantages and disadvantages of each are addressed in this section.

2.2 Installation Costs

Installation of UG lines is substantially more expensive than installation of OH lines. The reasons for the cost differential relate primarily to burial of the lines.

There are several methods by which lines can be undergrounded. These include:

- direct burial, whereby the insulated line is simply placed underground;
- installed within a direct burial duct, whereby insulated line is installed within a duct, or raceway; and
- installed within a concrete-encased duct.

Numerous factors affect the determination of which of the above burial methods is appropriate to employ, including access to unpaved land, the presence of other underground utilities, and soil and moisture conditions.

The costs to install UG lines vary by type of burial method, with direct burial being the least expensive and burial within a concrete-encased duct being the most expensive. While the cost of installation of OH lines is generally within the range of \$75,000 - \$125,000 per mile, the cost of installation of UG lines runs from about \$350,000 (plus or minus 50 percent) for an open area (i.e., using direct burial) to over \$2 million per mile for burial requiring roadways to be excavated and line burial within concrete-encased ducts.

2.2.3 Visibility of Problems

Overhead lines allow problems and faults to be easily identified because all facilities are above ground and visible. In contrast, for an underground system, the only items above ground are the distribution transformers, over-current protective devices, and line sectionalizing devices. Consequently, when problems emerge on an underground line, they are more difficult to locate because sight inspection is not possible.

2.2.4 Power-Carrying Capacity

Underground lines have lower carrying capacity than overhead lines of the same size. The reason for this differential is that overhead lines dissipate heat more effectively than underground lines. In general, an underground line will have a carrying capacity approximately 30 to 50 percent lower than an overhead line of comparable size depending on the type of undergrounding utilized.

2.2.5 Repair and Replacement of Damaged Conductors and Upgrading Facilities

Repairing or replacing damaged conductors on OH line is substantially easier, and less expensive, than similar work performed on UG line due to the ready access associated with an OH system compared to the reduced access for an underground system.

Similarly, upgrading facilities, for example, increasing the voltage level, is more easily accomplished on an overhead system than on an underground system. On overhead lines, conductor spacing and insulating supports can be modified to increase capacity or voltage level. For underground systems, the cable would need to be replaced to increase capacity or voltage level.

2.2.6 Aesthetic Considerations

One of the major advantages of UG lines is that they do not intrude upon the visual landscape. Overhead lines and poles are generally viewed as aesthetically displeasing.

2.2.7 Susceptibility to Damage

Overhead lines, because they are exposed, are susceptible to damage from wind, ice, and fallen tree limbs. Additionally, poles that support the lines are susceptible to damage from motor vehicles. Underground lines, because they are not exposed, are not susceptible to the same damage, though other factors can cause a fault in an underground system. Underground systems are more prone to failure from damage to insulation due to rodents. Furthermore, line insulation problems, e.g., a small hole in the insulation, will ultimately lead to a failure on an underground line. As noted above, line problems on a UG system are harder to isolate and repair than similar problems on an overhead system. It is noted, however, that the frequency of problems on an underground system is lower than on an OH system because the UG system is not exposed.

2.2.8 Inadvertent Contact

The likelihood of inadvertent contact, which could lead to injury or death, is higher for overhead lines than for UG lines due to the higher level of accessibility associated with OH lines. Consequently, conversion to UG lines has a safety-related benefit separate and distinct from benefits related to increased system reliability.

2.2.9 Operation and Maintenance (O&M) Costs

O&M costs tend to be lower for UG lines than for OH lines due to the lower frequency of failure. Based on information filed with the Federal Energy Regulatory Commission (FERC), O&M costs for OH line are about twice as much (on a per-mile basis) as O&M costs for UG line.

2.2.10 Other Issues

There are several other issues related to undergrounding line that warrant mention, particularly in the context of replacing existing OH line with UG line. First, when underground line is installed in areas having little unpaved area, it is often necessary to install the lines beneath the street. In addition to the direct costs associated with undergrounding the line, there are also adverse impacts on traffic, which needs to be re-routed during installation of the UG lines. Traffic disruptions inconvenience local residents, could adversely affect commuters, and may harm local businesses.

A second consideration is the difficulty in obtaining permission for placement of above-ground transformers in residential areas. Because a given above-ground transformer would serve several residences, as opposed to being a necessary piece of equipment to serve each individual residence, residential customers are hesitant to agree to have the transformer placed on their property and instead prefer it to be placed on a neighbor's property. Consequently, obtaining agreements for above-ground transformer placement is often time-consuming.

Undergrounding existing overhead electric facilities will affect other overhead utility services sharing the poles. For example, telephone and cable television lines typically share pole space with electric utility lines. Removal of the electric lines has two immediate impacts. The first relates to reliability of the telephone and cable television services because the electric lines are located above the other utility lines. Because of this configuration, falling branches first come into contact with the electric lines which provides some degree of protection for the telephone and cable television lines.

A second impact relates to cost. Absent the presence of overhead electric lines, the full cost of pole maintenance and replacement would be placed on the telephone and cable television services rather than shared among the three utility services. Therefore, while the electric utility customers may benefit from reduced O&M costs associated with underground lines, much of the saved cost would be shifted to telephone and cable television customers. Consequently, if neither the telephone lines nor cable television lines were undergrounded along with the electric lines, there may be little net savings to customers. Additionally, there would be no aesthetic enhancements since OH telephone and cable television lines would remain in place.

The presence of other utilities in addition to electric would, however, allow for the sharing of cost for undergrounding facilities were all utilities' lines to be converted to UG at the same time. Such an arrangement

would serve to eliminate maintenance costs for the pole lines and capture the aesthetic benefits associated with removal of the overhead lines and poles for all utility service providers.

3. Findings and Recommendations

3.1 Introduction

This section summarizes the key findings and conclusions of the analysis performed and presents the recommendations resulting from the analysis, including identification of issues requiring additional research.

3.2 Major Findings

3.2.1 System Vulnerability

During the January 1999 ice storm and Hurricane Floyd in September 1999, the transmission, subtransmission, and distribution substations were largely unaffected. The sections of the PEPCO and BGE systems that suffered severe damage that resulted in widespread and prolonged outages were the distribution mains, laterals from the mains, secondary conductors and service conductors to end-users. To minimize the likelihood of future problems of the magnitude of those experienced during and immediately following the extreme weather occurrences of 1999, those factors resulting in outages and long restoration times related to the electric distribution systems need to be addressed.

Damage to the BGE and PEPCO distribution systems was the result of ice accumulations on the lines well in excess of design parameters (January ice storm), fallen limbs (January ice storm and, to a lesser extent, Hurricane Floyd), and fallen trees (Hurricane Floyd). The damage to the electric distribution systems was substantial and, especially in the case of Hurricane Floyd, spread throughout the service areas of PEPCO and BGE. The ice storm resulted in distribution system damage within a narrow band through the Maryland portion of the PEPCO service area and a portion of BGE's service area.

Restoration times were prolonged due to several factors affecting the ability of the utilities to get equipment and crews into affected areas, including:

- the inability of the utilities to get equipment in to repair the OH lines located in residential back lots;
- outages located on peninsular areas having limited access for equipment due to downed trees; and
- numerous roadways blocked by fallen trees, making equipment deployment sometimes impossible.

3.2.2 Cost

The cost of converting OH distribution lines to underground varies substantially depending upon the specific characteristics of the area, including topography, geology and land use. Cost estimates range from

\$350,000 per mile to over \$2 million per mile depending on local area circumstances. Assuming an average installation cost of \$450,000 per mile, the cost of converting BGE's existing OH distribution system (approximately 9,400 miles) would be approximately \$4.2 billion; converting PEPCO's approximately 12,700 miles OH distribution system would be \$5.7 billion. Were these costs to be spread to ratepayers based on generally accepted cost allocation methodologies, these costs would be allocated primarily to residential and small commercial customers, that is, those customers receiving power at distribution voltage levels.

For BGE, per-kWh costs to residential and small commercial customers for converting the entire OH distribution system to underground are estimated to be \$0.032. For residential customers using 900 kWh per month, which approximates total residential usage on an average monthly basis divided by total residential customers, annual costs would increase by approximately \$340. For PEPCO residential customers, average annual costs would increase by approximately \$415. These increases equate to percentage rate increases of 36 percent and 46 percent for residential customers of BGE and PEPCO, respectively.

Undergrounding service conductors to residential customers would add significantly to the cost of undergrounding the distribution system. The one-time cost of undergrounding secondaries and service conductors to residential customers is estimated to range between \$1,500 and \$3,000 per customer, including the cost for an on-site electrician to convert the service from overhead to underground at the customer's meter.

In addition to direct costs, certain indirect costs to local residents would be incurred related to disruption of traffic for lines that need to be located beneath streets. Disruption of traffic could also adversely affect local merchants. For lines that are buried along the side of roadways, residences may incur damage to lawns and landscaping.

The cost figures presented above are based on conversion of all OH distribution lines to underground. To the extent that only selected sections of the OH distribution systems are converted to underground, the costs shown above are overstated. It is important to emphasize, however, that there are substantial differentials in the cost to underground facilities owing to differences in local conditions. Similarly, there are differences in the benefits associated with converting different portions of the overhead distribution system in terms of reliability and other ancillary considerations. The differences in costs and benefits for undergrounding different portions of the utilities' distributions systems provide a quantitative basis for selecting and establishing priorities for conversion activity.

3.2.3 Funding Methods

A separate cost-related issue is the determination of the method (or methods) by which conversion of OH lines to underground would be funded. Potential funding methods include:

- funding by the State;
- funding by local government;
- funding through utility rates, i.e., ratepayer funding;
- funding provided by those utility customers receiving the direct benefit from conversion of OH lines to underground; and
- funding from other conduit users providing telephone and/or cable television service.

The wide-ranging nature of the benefits associated with undergrounding suggests that a broad-based funding approach relying on a combination of funding mechanisms is appropriate.

3.3 Recommendations

Based on the analysis performed and the findings/conclusions that have emerged, the following recommendations are made:

1. Conversion of the entire aerial electric distribution systems of the Maryland utilities does not appear to be viable based on installation costs. Instead, emphasis should be directed towards undergrounding selected portions of the utilities' distribution systems, with the establishment of priorities based on cost, impact on improved reliability, and ancillary considerations such as aesthetics and traffic impacts.
2. An undergrounding pilot program should be adopted wherein each utility would identify four or five different areas, each requiring different types of underground construction. Costs and other relevant factors should be carefully monitored and tracked to enable development of a full and comprehensive analysis of undergrounding issues. Among the items to be monitored and tracked in addition to installation costs should be:
 - a. impacts on other OH utilities (e.g., telephone, cable television);
 - b. difficulties encountered in obtaining permission for placement of above-ground transformers;
 - c. traffic disruption;
 - d. reliability impacts;
 - e. qualitative assessments regarding improved access for emergency vehicles (e.g., fire trucks), aesthetic considerations, and reduced requirements for tree trimming and vegetation management.

To the extent that utilities have performed recent conversion of OH lines to UG, the pilot program need not require additional conversion if accurate cost data are available and other useful data and information from the project can be reconstructed or monitored.

3. Additional research should be conducted on the impacts of undergrounding electric utility distribution lines on other OH utility systems.

4. Several funding methods for undergrounding existing electric distribution system lines were identified. It is recommended that a funding approach be developed for those portions of the electric distribution system that have the greatest effect on reliability.

5. Tree trimming and vegetation management practices should be reviewed to ensure balance between utility distribution system reliability and other legitimate policy goals.

APPENDIX

Meetings/Interviews Conducted

Baltimore Gas and Electric Company

Brian C. Daschbach, Sr. (Manager Transmission & Distribution, Operations & Maintenance)

Brian R. Chappell (Director of System & Reliability Planning and Electric System Operations & Planning Department)

Betty Ferguson (Customer Care Director)

John Glenn (Customer Care Supervisor)

Marianne Weiss (Customer Care Training Supervisor)

Bernard Sheffield (Customer Care Liaison Specialist)

Ed Carmen (Senior Engineer, Electric System Operations & Planning)

Potomac Electric Power Company

D. A. Basile (Manager Distribution Engineering and Construction)

Ted Ryan (Manager Customer Design and Construction)

Mike Maxwell (Control Center Operations)

George Gasler (Control Center Operations)

Shawn Kelly (Control Center Operations)

International Brotherhood of Electrical Workers

James Hunter (Local 1900 IBEW Business Manager)

APPENDIX C

**Report to the
Public Service Commission of Maryland
on the Selective Undergrounding
of Electric Transmission
and Distribution Plant**

February 14, 2000

Prepared by

The Selective Undergrounding Working Group

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I. Summary

A. Purpose and Content of Report

The purpose of this report is to document the work, findings and recommendations of the Case No. 8826 Selective Undergrounding Working Group in the study of selectively undergrounding segments of utility transmission and distribution systems as a possible means of limiting the frequency or duration of electric power outages. This work was performed at the direction of the Maryland Public Service Commission pursuant to Order No. 75823, which was issued on December 9, 1999 in Case No. 8826, "In the Matter of the Investigation into the Preparedness of the Maryland Utilities for Responding to Major Outages." The formation of the Working Group is the result of the Commission's request that a collaborative process be initiated to consider the benefits and detriments of selectively undergrounding segments of utility transmission and distribution systems. Specifically, considerations were to include but not be limited to the costs, durability of underground systems, risk of damage, relative duration of outages (compared to aerial facilities), and aesthetics. Other considerations include the effect of undergrounding on customer-owned facilities, the stranding or displacement of other utilities (e.g., telecommunications and cable TV) when converting overhead electric facilities and additional electrical power equipment requirements. This report documents the Working Group's findings and recommendations regarding these considerations and their associated interrelationship in the analysis of the selective undergrounding of electrical power lines.

The participants in the Selective Undergrounding Working Group were:

Allegheny Power
Baltimore Gas and Electric Company (BGE)
Bell Atlantic
Choptank Electric Cooperative
Connectiv
Potomac Electric Power Company (PEPCO)

Southern Maryland Electric Cooperative
Maryland Energy Administration
Power Plant Research Program
Office of People's Counsel
Commission Staff

B. Results of Report

1. Findings

Selective undergrounding of overhead electric lines may be desirable for aesthetic or public policy reasons (e.g., to improve older urban areas), however the impact on reliability is unclear and the costs are substantial.

Undergrounding of electric transmission and distribution facilities reduces their exposure to certain causes of outages, particularly those associated with storms. Undergrounding may, therefore, limit the *frequency* of *storm-related* outages, except when there is widespread flooding of underground conduits.

In *normal weather* and over the *long run*, there is insufficient evidence to support the proposition that underground lines suffer fewer outages than overhead lines. There is some evidence to support the opposite conclusion. There is considerable evidence that underground cable installed before 1985 has become unreliable and offers a much shorter useful life relative to overhead lines. There is insufficient long-term experience with new cable to reach firm conclusions as to whether advances in cable materials will increase reliability over a cable's useful life.

Historically, underground lines offer improved reliability in the early years of their service lives. As older vintage cable deteriorates over time, however, underground reliability degrades greatly in relation to overhead lines. Ultimately, when wholesale cable replacements are required to restore reliable service, the substantial additional costs of undergrounding are incurred again and communities are disrupted as ground is broken, roads are detoured, and lawns are excavated.

It is more difficult to locate and repair subsurface faults and cable failures, and the *duration* of underground repairs tends to greatly exceed that of overhead repairs.

In contrast to underground cable, overhead lines are both visible and easily accessible, which facilitates quicker and less expensive service restoration.

While there are questions about the long-term reliability of underground lines, the relative costs of underground and overhead installations are quite clear. The average cost of electric underground installations in Maryland, studied herein, is approximately \$900,000 per mile, which is anywhere from 5 to 10 times more costly than the average for comparable overhead installations. Moreover, the useful life of underground cable is about 30 years compared to a 50-year life of overhead plant.

Given this huge capital cost differential and relatively shorter useful life of underground installations, overhead lines offer a much less expensive method of providing reliable electric service, which lowers electric rates to consumers. This statement holds true even after factoring in the costs of routine overhead maintenance, such as tree trimming, and periodic replacement of infrastructure damaged by storms and man-made causes¹.

In this regard, if a 10 percent return is imputed to the great amounts of capital freed up by building overhead instead of underground lines, the earnings alone will pay for substantial ongoing overhead maintenance. See Section IIIB for case studies of the significant¹ lower costs of improving overhead reliability.

Selective undergrounding of electric facilities, while technically an option for addressing substandard reliability of service to customers, is generally not the best, nor the most cost effective means of doing so. For a variety of economical alternatives to improve reliability, see Section IID of this report.

¹ The Working Group did not attempt to measure economic losses associated with either overhead or underground outages.

Still, there are occasional circumstances when selective undergrounding may be the only suitable option for addressing electric reliability problems. See Section IID of this report for a discussion of the process and prerequisites to electric undergrounding. It should also be noted that undergrounding of telecommunication facilities attached to existing overhead electric power lines reduces their associated reliability.

Typically, overhead lines are placed underground for reasons unrelated to reliability, such as aesthetics in the location of the facilities, and such objectives may have merit as a matter of public policy. Electric consumers are now free to choose to pay for such projects under the Commission's well-established cost-causation policy.

If the electric utilities are required to make changes to their current undergrounding practices, then the Commission will need to address issues concerning cost-recovery in light of The Electric Customer Choice and Competition Act of 1999 and associated settlements. Telecommunication utilities have similar concerns.

2. Recommendations

Based on the above findings, it is recommended that the utilities continue to underground electrical and other facilities under the same circumstances as presently occurs. Specifically, these circumstances include: as mandated by COMAR 20.85.01 – 20.85.05², at the customer's request, or as appropriate for reliability reasons (See Section IID).

It is recognized, however, that with the improvement of available technology, the installation and long-term operation and maintenance costs of underground electric facilities may decline, while their durability and other operating

² These COMAR provisions require undergrounding of extensions of electrical distribution lines necessary to furnish permanent electric service to new commercial and industrial buildings, multiple-occupancy buildings and new residential buildings.

characteristics may improve. Such changes in the state of the industry may make the selective undergrounding of electrical power facilities a more cost effective and viable means of improving service reliability to customers in the future.

Therefore, the Working Group recommends that when other reliability initiatives fail and undergrounding is necessary to improve service, utilities should keep detailed cost and operation information concerning the subject line section over the service life of the underground project. This information, where available, should include such data as the undergrounding construction costs, reliability data (including both indices and specific causes of outages before and after the undergrounding), customers affected and location in the electrical system. This information could then be reviewed and used as a basis for reevaluating the viability of selective undergrounding for other reliability oriented projects in the future.

II. Discussion

A. Introduction

On December 9, 1999, Order No. 75823 was issued by the Public Service Commission of Maryland in Case No. 8826. As part of that order, the Commission indicated that a "collaborative process with parties including utilities, Staff, MEA/PPRP and others" be initiated to examine issues associated with the benefits and detriments of selectively undergrounding segments of the utility transmission and distribution systems. These parties, working as the Case No. 8826 Selective Undergrounding Working Group were directed to address such associated considerations as costs, durability of underground systems, risk of damage and the relative duration of outages (compared to aerial facilities), and aesthetics as well as other issues which may be appropriate. It is the purpose of this report to document the Working Group's findings with regard to these considerations.

In the development of this report, the Working Group reviewed and discussed the following references:

1. Order No. 75823, issued in Case No. 8826, "In the Matter of the Investigation into the Preparedness of the Maryland Utilities for Responding to Major Outages."
2. "Undergrounding Electric Utility Lines in Maryland," prepared for the Maryland Energy Administration and the Power Plant Research Program by Exeter Associates, Inc. on December 30, 1999.
3. Cost data for the construction/installation for the undergrounding of line facilities as obtained from the electric and telephone utilities of the State of Maryland. (See Section IIIB.)

4. Reliability (outage) data for the operation of overhead and underground line facilities as obtained from the electric utilities of the State of Maryland. (See Section IIIB.)
5. The engineering, construction, operation and maintenance practices, policies and experience of the electric and telephone utilities of the State of Maryland.

This report discusses issues associated with undergrounding of electric distribution lines. The Working Group finds that transmission lines are considerably more costly to underground on a per mile basis and because of the nature of their established route corridors, tend to be considerably less susceptible to power interruptions. Similarly, Exeter Associates noted in its report that the transmission systems of BGE and PEPCO were not affected by the severe weather occurrences of 1999 (Exeter Report, p. 3). Thus, the Working Group's focus was also directed at the evaluation of distribution facilities. With lower undergrounding costs and more frequent outage rates (vs. transmission), undergrounding distribution facilities would stand the greater chance of being economically justified.

B. Considerations Directed by the Commission

In addressing the considerations directed by the Commission in Order No. 75823, the following were found:

1. Cost

Given the magnitude of construction costs, all parties agreed that the large-scale undergrounding of electric power (and other utility) lines is not a wholesale, viable means of improving reliability (Order No. 75823, p. 67). Costs associated with the undergrounding of overhead distribution power lines in the State of Maryland are indeed high. Analyses of recently planned projects range from \$367,000 per mile (Allegheny Power Damascus Project) to \$2.1 million per mile (Connectiv Ocean City Project) with a typical average of nearly \$900,000 per mile as indicated in the chart below. (For supporting data see Section IIIB.)

**COST/MILE UNDERGROUNDING CALCULATIONS
BASED ON DATA REQUESTED BY
MARYLAND PUBLIC SERVICE COMMISSION FOR
SELECTIVE UNDERGROUND WORKING GROUP
MEETING OF JANUARY 20, 2000**

UTILITY	TOTAL OF PROJECT COSTS	TOTAL OF PROJECT FOOTAGES	TOTAL OF PROJECT MILEAGES	AVERAGE COST/FOOT	AVERAGE COST/MILE
ALLEGHENY POWER	3,059,488	21,125	4.0	\$145	\$764,655
BGE	4,800,000	26,620	5.0	\$180	\$960,068
PEPCO	5,500,000	16,600	2.0	\$346	\$1,826,415
CONNECTIV	11,336,500	82,200	15.6	\$138	\$728,150
TOTALS	24,696,088	145,846	27.6	\$169	\$894,062

These costs were independently compiled and represent a cross-section of urban, suburban and rural settings. It should be noted that these costs are on the order of 5-10 times greater than the average costs associated with comparable overhead routings. In addition to the costs for electrical undergrounding, the cost to underground attached telecommunication facilities is also high. Additional costs for telecommunication undergrounding tend to average \$222 per foot or \$1,172,200 per mile. (See Bell Atlantic data from Section IIIB.)

2. Durability of Underground Systems

The long-term durability of underground lines is generally less than that of counterpart overhead lines over the course of their respective service lives. Whereas overhead lines are exposed to atmospheric weathering and above-ground plants and animals, underground lines are exposed to natural, ground-level problem-causing agents which tend to encumber their operation and maintenance. These include:

- Moisture, especially due to the flooding of conduit systems.
- Overvoltage impulses due to lightning strikes.

- Electrolytic breakdown due to unfavorable soil conditions.
- Infestation by ground-borne animals such as snakes and rodents.
- Shifting and settling of the earth.
- Reduced accessibility or direct infestation caused by nearby trees and shrubs.

These problem-causing agents lead to the failure of underground cable over time, requiring either specialized maintenance or replacement. Presently, the Maryland electrical utilities are finding:

- Older cable, 25-35 years of age, is failing.
- Newer cable should last longer but still not as long as overhead lines.
- When any underground cable fails at the end of its service life it becomes a major replacement cost and reliability problem.

While it may seem counter-intuitive to suggest that overhead lines may be more reliable than underground installations, Conectiv provided evidence where an existing section of failing underground line on its Fruitland 2266 25-kV feeder was replaced with an overhead section of line and showed a marked improvement in reliability (See Section IIIB). Similarly, as noted in Order No. 75823, PEPCO compared a group of 40-year old overhead feeders to a group of 20-year old underground feeders and found that customers supplied by an overhead trunk circuit over a nearly 5-year period experienced fewer outages than similar customers served by an underground trunk.

Frequency of outage data, however, is not uniform. System Average Interruption Frequency Index (SAIFI), values for overhead lines were better than underground lines in 1996 for Allegheny and for all utilities in 1998, but results differ in other years (See Section IIIB).

3. Risk of Damage

Risk of storm and motor vehicle damage is generally lower for underground lines than for their overhead counterparts. However, there is considered to be a significant risk of damage associated with excavating in the vicinity of underground facilities (that is, "dig-in" risk). In Working Group discussions, Bell Atlantic stated that the reliability of their communication facilities generally decreased with undergrounding due to dig-ins. BGE noted that it experienced 858 damages to underground cables in 1998 and 832 such damages in 1999. Similarly, PEPCO cited statistics of 522 damages to underground cables in 1998 and 610 such damages in 1999 (See Section IIIB). Also, the close proximity of padmounted transformers and other necessary devices to driving surfaces lead to periodic contacts with motor vehicles. Although this can be addressed through installing barriers or moving the subject facilities farther from the roadway, both solutions require additional expenditures and tend to reduce local aesthetics.

4. Relative Duration of Outages Compared to Aerial Facilities

As indicated in the previous section, the risk of storm and motor vehicle damage is generally lower for underground lines than for their overhead counterparts. However, when outages on underground lines occur, the outage duration tends to be longer because of the inaccessibility of underground facilities. Most System Average Interruption Duration Index (SAIDI) values in case studies over the period 1996 – 1998 support the proposition of increased durations of underground outages (See Section IIIB). Typically, the outage time associated with an occurrence of a section of overhead line may be 1 to 2 hours. The outage time associated with the outage of a comparable section of underground line may be 3 to 6 hours. This can be addressed by providing alternative supplies (i.e., "looping"); however, this requires additional expenditures and is dependent on the availability of routes for such alternative supplies.

5. Aesthetics

The aesthetic appearance of underground utility facilities is generally accepted as better than that of comparable overhead facilities. However, there exists the issue of the placement of the padmounted transformers and other necessary devices which lead to the localized presence of underground facilities being less desirable. This can encumber efforts to obtain rights-of-way and the effective placement of these devices. Even once agreements are reached and facilities placed, underground facilities are still subject to the unauthorized screening attempts on the part of the property owner. Such screening attempts, taking the form of trees, shrubs or other barriers, encumber the operation and maintenance of the facilities as cited in Section 2 above.

C. Other Considerations

In addition to the considerations specified by the Commission in Order No. 75823, the following were considered to be critical in the analysis of selectively undergrounding of electric line facilities:

1. Customer Owned Facilities

If electric facilities were undergrounded in a given region, there would be the issue of who would bear costs associated with customer interfacing (i.e., is meter socket, and panel modification cost) that would be required for the customer to continue to take service from the local system. Typical costs for such work fall between \$1,000 and \$2,000.

2. Attachment of Other Utilities to Electric Facilities

If electric facilities were undergrounded along line sections where other utility and government facilities were attached, there would be the issue of who would be responsible for poles and maintenance if the remaining utilities would or could elect to remain overhead. In the same situation, there would be the issue of who would be responsible for the cost if those same utilities were to be put underground.

3. Additional Equipment Requirements

If longer electric power lines were undergrounded along their main-line sections, electric utilities would have to underground or padmount specialized equipment which, to date, they have not done. Devices such as capacitors, reclosers and voltage regulators, which presently have only been attached to overhead facilities, would be cumbersome, expensive and aesthetically displeasing to install if done so in an underground or padmounted form.

D. Undergrounding in the Process of Reliability Improvement

Given the high cost of undergrounding lines and the considerations discussed above, The Working Group concludes that undergrounding of overhead power lines generally is not be the best solution for improving operational reliability and only becomes an option of last resort in a case-specific evaluation process. In such a process, all of the various factors affecting reliability of a given subject line would first have to be taken into account. These would include :

- Type and number of customers affected.
- Location and mileage of line whose reliability is substandard.
- Magnitude of reliability indices for the subject line.
- Length of time which reliability of the subject line is substandard.
- Circuit layout and whether the subject line is a main trunk line or lateral tap.
- Analysis of the actual causes of the substandard reliability.
- Likelihood of the return of the causes.

Taking all of these factors into account, a broad-based process would then be applied to address the reliability issue. In this process, multiple years of reliability performance data would need to be reviewed, with focus on the causes and locations of outage events. A determination would need to be made of the effectiveness of past remedies including routine maintenance and applied reliability solutions. Further, the actual number of

customers that would benefit from various possible solutions would have to be determined. With this accomplished, a field review of the area would need to be performed, noting among other things, the condition of the trees. Consideration would then be given to the following options:

- Enhanced tree trimming.
- Tree wire, aerial cable and spacer cable.
- Overhead infrared inspection.
- Enhanced wildlife and lightning protection.
- Better sectionalizing through additional fusing.
- Changing overhead construction from crossarm to armless design.
- Relocating the line (overhead) to a less tree covered or otherwise compromised route.
- Selectively undergrounding portions of the line.

After implementing this process and scrutinizing the alternatives, undergrounding may become the only viable means of providing the required improvement in reliability in the subject case. Thus, selective undergrounding is simply one of many means for addressing reliability issues, and it is clearly the most capital intensive.

Based on the above discussion and the data reviewed in the preparation of this report, the Working Group put forth the Findings and Recommendations in the Summary of this report.

III. Appendices

A. Working Group's Commentary on Exeter Associates' report to MEA/PPRP

Since the report prepared for the MEA/PPRP by Exeter Associates cited in Section IIA, generally examined the same issues as this report, the Working Group offers the following commentary on Exeter's results. Although the Working Group's findings were generally the same as those of Exeter's, the Working Group wishes to add certain qualifications or clarifications. In the listing below, the finding, conclusion or recommendation has been taken verbatim from the Exeter report. It is then followed by the Working Group's comment. A complete copy of the Exeter report is attached for reference.

Comments on Exeter Associates' "Findings and Conclusions"

1. The utilities' transmission systems, sub-transmission systems, and substations were largely unaffected by the ice storm and Hurricane Floyd and significant restoration efforts for these system components were not required.

Comment – The Working Group agrees.

2. Almost all of the restoration efforts related to the ice storm and Hurricane Floyd were directed toward distribution mains, distribution laterals from mains, secondary conductors, and service conductors directly connecting end-users.

Comment – The Working Group agrees.

3. Relative to overhead lines, underground lines offer advantages in terms of aesthetics; reduced susceptibility to damage from wind, ice, and vehicles; reduced operation and maintenance costs; and minimization of inadvertent contact with lines by people and animals.

Comment – The Working Group has reviewed information that questions the finding that underground lines offer advantages of reduced operation and

maintenance costs and minimization of inadvertent contact with lines by people. Also, the Working Group notes that underground facilities are susceptible to damage from vehicles. Otherwise, the Working Group agrees.

4. Relative to overhead lines, underground lines present disadvantages in terms of installation costs; power-carrying capacity; the ease (and cost) of locating and correcting problems on the lines; the ease of performing system upgrades; and certain ancillary concerns such as traffic disruption during installation, arranging for placement of above-ground transformers on private property, and possible impacts on other above-ground utility systems, e.g., telephone and cable television.

Comment – The Working Group agrees.

5. Assuming an average cost per mile of \$450,000 for undergrounding the existing OH distribution systems of PEPCO and BGE, the cost of undergrounding would result in substantial increases in electric utility rates if funding for undergrounding were to be collected fully from distribution service ratepayers. Increases in residential rates are estimated to be approximately 36 percent for BGE customers (or an increase of approximately \$340 per year) and 46 percent for PEPCO customers (or an increase of approximately \$415 per year).

Comment – The Working Group generally agrees. However, the average cost per mile quoted is near the lower bound of the range found by Exeter. Maryland utility experience to date has shown the average cost to approach \$900,000 per mile. This later figure is consistent with the Exeter study.

6. Costs for undergrounding existing overhead lines vary significantly depending on the specific characteristics of the area such as topography, geology, and land use.

Comment – The Working Group generally agrees. However, it feels that system design should be added to the list of specific characteristics with which costs for undergrounding existing overhead lines vary.

7. Completion of conversion to UG lines for substantial portions of the OH distribution system will likely require 15 to 20 years for planning, design and construction.

Comment – The Working Group generally agrees although the required time for the planning, design and construction for underground line conversion may vary.

Comments on Exeter Associates' "Recommendations"

1. Conversion of the entire aerial distribution systems of the Maryland utilities does not appear to be viable based on installation cost.

Comment – The Working Group agrees.

2. Undergrounding for selected portions of the utilities' distribution systems should be adopted, with prioritization established based on cost, impact on improved reliability, and ancillary considerations (e.g., aesthetics, traffic impacts).

Comment – The Working Group believes that undergrounding for selected portions of the utilities' distribution system should be considered as one of many means for improving reliability.

3. A pilot program should be adopted wherein each utility would identify four to five different areas, each requiring different types of underground construction. Costs and other relevant factors should be carefully tracked to enable development of a full and comprehensive analysis of undergrounding issues. Among the items to be monitored and tracked in addition to installation costs are: impacts on other OH utility systems; difficulties that may be encountered with obtaining permission for placement of above-ground transformers; traffic disruption; reliability improvements; and qualitative assessments regarding improved access for emergency equipment (e.g., fire trucks), aesthetic

considerations, and reduced requirements for tree trimming and vegetation management.

To the extent that utilities have performed recent conversion of OH lines to UG, the pilot program need not require additional conversion if accurate cost data are available and other desirable data and information from the project can be reconstructed or monitored.

Comment – The Working Group generally believes that each of the utilities has accurate cost data and can provide reliable cost comparisons for any undergrounding project. Therefore the development of a pilot project would not provide significant additional information. However, many of the utilities are currently designing or have recently completed undergrounding projects that have generally been performed for aesthetic consideration. These projects have been funded by various governmental organizations and could be used to review the actual cost and impact on a community.

4. Additional research should be conducted on the impacts of undergrounding electric utility lines on other OH utility systems (i.e., telecommunication, cable TV, etc.).

Comment – The Working Group agrees. However, the Working Group believes it has accomplished the additional research with respect to telecommunication facilities, but additional research may be necessary to determine the impact on cable TV and other overhead systems.

5. Several funding methods for undergrounding existing OH distribution lines were identified, including:

- a. State funding;
- b. local government funding;
- c. ratepayer funding;

- d. funding from those customers receiving direct benefit; and
- e. funding from other conduit users providing communication services.

The wide range of benefits associated with undergrounding select portions of the electric utilities' distribution systems suggests a broad funding mechanism is appropriate. A combination of the potential funding sources appears warranted and it is recommended that a funding approach be developed for those portions of the electric distribution systems that have the greatest effect of reliability.

Comment – The Working Group generally agrees. However, there are benefits and detriments to selective undergrounding as discussed in this report.

- 6. Tree trimming and vegetation management practices should be reviewed to ensure balance between utility distribution system reliability with other legitimate policy objectives.

Comment – The Working Group agrees.

B. Cost and Reliability Data of Maryland Utilities

The documents on the attached pages are copies of utility responses to requests for data during the Working Group Meeting of January 20, 1999. These responses were to provide the following data:

Costs to Improve Reliability

1. Select an overhead feeder identified by your company for focused/special/reliability-driven maintenance. This feeder must have at least 12 months of outage history AFTER the focused/special/reliability-driven maintenance was completed.
2. Provide SAIFI and SAIDI, as defined in IEEE P1366/D19, for the feeder for the 12 months preceding the start of the focused/special/reliability driven maintenance. Provide the indices for all weather events as well as without major storms.
3. Summarize the focused/special/reliability-driven maintenance done on the feeder and provide the total cost. Include when the maintenance was initiated and when it was completed.
4. Provide SAIFI and SAIDI, as defined in IEEE P1366/D19, for the feeder for 12 months after the start of the focused/special/reliability driven maintenance. Provide the indices for all weather events as well as without major storms.
5. Provide a cost estimate to underground the feeder, specifying whether construction is looped or radial. Provide a reasonable break-down of costs into categories, including costs to remove overhead facilities.

Reliability of Overhead vs. Underground

1. Select two feeders, one primarily overhead and one primarily underground in close geographic proximity to each other. If you can query your outage records to a finer level, pick two communities.
2. Provide SAIFI and SAIDI, as defined in IEEE P1366/D19, for the feeders or communities for each of the past three calendar years. Provide the indices for all weather events as well as without major storms.
3. Include a detailed enough description of the location and composition of the feeders to be convincing that they are comparable.

Conversion Cost Data

Provide cost information on a recent overhead to underground conversion project. If possible, use a project that represents a mid-range in cost. Include other utility costs (Bell Atlantic, cable TV), as appropriate.

In the development of this report, the responses to the above requests on the attached pages were analyzed based on the technical information and expertise provided by the Working Group's members. Because of the variability of the data, this in-depth analysis was necessary so as to be able to properly use the data in the report's development. Such analyses into the specific causes and conditions behind the varying magnitudes of cost and reliability indices were necessary to develop substantive conclusions for the report.

In addition to the cost and reliability data requested by Staff, the Working Group felt it appropriate to include statistics on the number of cases of cable damage incurred due to excavating (That is, "dig-ins"). This data has been included as an additional attachment.

MARYLAND PSC WORKING GROUP – CASE 8826
 SELECTIVE UNDERGROUND WORKING GROUP
 DATA REQUEST FOR JANUARY 20, 2000
 ALLEGHENY POWER

Costs to improve reliability

1. *Select an overhead feeder identified by your company for focused/special/reliability-driven maintenance. This feeder must have at least 12 months of outage history AFTER the focused/special/reliability-driven maintenance was completed.*

Answer: Myersville Substation, Wolfsville feeder- 1993. This feeder is primarily rural serving a large portion of central and northwestern Frederick County. It is primarily a rural circuit.

2. *Provide SAIFI and SAIDI, as defined in IEEE P1366/D19, for the feeder for the 12 months preceding the start of the focused/special/reliability driven maintenance. Provide the indices for all weather events as well as without major storms.*

Answer: See #4 below

3. *Summarize the focused/special/reliability-driven maintenance done on the feeder and provide the total cost. Include when the maintenance was initiated and when it was completed.*

Answer: Circuit was experiencing poor reliability on an on-going basis. Because of this, the circuit was identified to have extensive tree trimming activities performed on it during 1993. The cost to do so, which included a significant amount of tree removal, was initiated and completed in 1993 at a cost of \$750k.

4. *Provide SAIFI and SAIDI, as defined in IEEE P1366/D19, for the feeder for 12 months after the start of the focused/special/reliability driven maintenance. Provide the indices for all weather events as well as without major storms.*

Answer: Reliability data for the circuit was as follows:

<u>Year</u>	<u>SAIFI</u>	<u>SAIDI</u>
1992 (prior to work, all weather)	2.66	563.85
1993 (all weather)	.73	483.40
1993 (without storms 3-4,3-5, 3-13, 3-14)	.60	135.87
1994 (after work completed, all weather)	.26	100.42

Note: There were no major storms of record in 1992 or 1994

5. *Provide a cost estimate to underground the feeder, specifying whether construction is looped or radial. Provide a reasonable breakdown of costs into categories, including costs to remove overhead facilities.*

Answer: The construction of the underground would be radial with no other sources or feeders readily available in this area. Mainline distance of feeder is approximately 14 miles with a total line mileage of 96 miles. Using average cost to underground of \$350k mile for mainline and \$53k per mile of single phase, the total cost to place the entire feeder underground would be \$9,246k plus costs of removal and transformers.

Reliability of Overhead vs. Underground

1. *Select two feeders, one primarily overhead and one primarily underground in close geographic proximity to each other. If you can query your outage records to a finer level, pick two communities.*

Answer: The circuits selected are the Brigadoon and McCain Drive circuits served out of the McCain Substation located in the western end of Frederick, Maryland.

2. *Provide SAIFI and SAIDI, as defined in IEEE P1366/D19, for the feeders or communities for each of the past three calendar years. Provide the indices for all weather events as well as without major storms.*

Answer:	<u>McCain Drive Circuit</u>	<u>SAIFI</u>	<u>SAIDI</u>
	1998	1.29	91.07
	1997	0.91	569.88
	1996	0.28	49.40
	<u>Brigadoon Circuit</u>	<u>SAIFI</u>	<u>SAIDI</u>
	1998	0.04	4.59
	1997	1.73	124.96
	1996	0.11	25.16

Note: Reliability data on Brigadoon Circuit affected by an outage on the underground in 1997.

3. *Include a detailed enough description of the location and composition of the feeders to be convincing that they are comparable.*

Answer: The two circuits have been selected that feed the same basic direction from the station, have approximately about the same line lengths and number of customers. The detail is as follows:

<u>Substation</u>	<u>Feeder</u>	<u>OH Line Miles</u>	<u>UG Line Miles</u>	<u>Customers</u>
McCain	McCain Drive	0.14	8.23	476
McCain	Brigadoon	7.03	1.89	501

These circuits both leave the substation and serve in a northerly direction. The Brigadoon feeder serves an area to the east of McCain Drive basically separated by Route 15. Both serve primarily residential areas in the west end of Frederick separated by approximately one mile in their service areas.

Conversion Cost Data

Provide cost information on a recent overhead to underground conversion project. If possible, use a project that represents a mid-range in cost.

Include other utility costs (Bell Atlantic, CATV), as appropriate.

Answer: Allegheny Power has participated in a number of underground projects over the last eight years. Although only one was requested in the data request, the following provides data for those that were identified and available along with a description of the project. All Allegheny Power costs identified below are capital costs only and do not include transformer material costs nor Operation and Maintenance costs. These costs were not readily available in the timeframe available and without some significant investigation:

1. Damascus project – 1992-1994- total capital costs- \$598,000 for a mainline distance of 1.63 miles (average cost of \$367k/mile). Costs were not readily available for other utility costs, or costs that the county may have incurred. The County would have borne the costs of any wiring requirements by the customer.
2. Frederick City – 1993-1995 – 2170 feet of OH-UG conversion for a cost of \$471,142 (average of \$1,146,373 per mile. This was a rather extensive project that included 34.5 kV circuits (2) as well as distribution mainline. The costs were driven up by bad weather (extensive rain) as well as significant traffic in the area. Costs do not include customer rewiring and other utility costs.
3. Frederick City – Montevue Lane Project – 1995-1996- 3605 feet of mainline at a cost of \$275k, or an average of \$ 403k/mile. This was a rather straightforward project away from downtown area along a suburban road. Costs do include rewiring of houses, as necessary, which Allegheny Power coordinated. Road was fairly well traveled. Costs do not include other utility costs.
4. Damascus SS, new feeder- although not a conversion, this was a project to bury a new feeder through a parkland and residential area. The mainline distance was 5085 feet installed at a cost of \$358,251 (average of \$372k/mile). Neither other utility costs nor customer costs would have been involved in this project.
5. Frederick Patrick Street project (proposed- 1996 estimate) – not constructed yet, this is the most recent project Allegheny Power has active in Maryland. Scheduled for 2001-2002 presently. Allegheny's costs have been quoted as \$681,864 for a distance of 2200 feet (averages \$1,636k/mile). This project is located in the middle of town through a highly commercial area and very highly traveled portion of town. The impacts on customers will be significant. Proposed other utility costs, and customer costs not included. Costs also do not include trenching costs to be performed by the Town of Frederick in their road contract. Presently it has been discussed that the project may be completed in two parts (each side of the street) which has a significant impact on costs because of the complexities of working project in that manner. Since these are estimated costs, they do include transformer costs as well as O&M costs.

BELL ATLANTIC
SAMPLE of COSTS to UNDERGROUND CABLE FACILITIES

Location / Description	# of Cables	Linear Footage	Total Cable Footage	Cost	Cost per Linear Foot	Comments
Ocean City, 15th - 33rd Sts	4	5,000	55,294	\$ 1,158,692	\$ 231.74	Includes estimated cost of MH & conduit paid for by Ocean City. Does not include R/W costs. Extensive customer service drop and terminal work.
Lanham, Rt. 450	4	1,300	5,200	\$ 1,100,000	\$ 846.15	1 fiber, 3 copper cables. Some portion of job was constructed at 8' depths. Actual costs.
Bellsville Cherry Hill & Powder Mill Rds	6	800	4,800	\$ 822,000	\$ 1,027.50	Job in progress. Estimated final costs.
Hartford County, Perryman Rd	1	2,800	2,500	\$ 150,000	\$ 53.57	1 600 pair cable. Actual costs.
Hartford County, Rt. 1	3	3,000	9,000	\$ 500,000	\$ 166.67	Job in progress. Estimated final costs.
Annapolis, Gateway Circle	9	4,300	43,200	\$ 900,000	\$ 187.50	3 fiber, 6 copper cables. Includes actual Bell Atlantic costs plus estimated costs of MH & conduit work provided by Annapolis.
Scaggsville, Rt 29 & Rt 216	8	10,300	82,400	\$ 1,600,000	\$ 155.34	Job in progress. Estimated final costs.
Edgewater, Rt 2 & Mayo Rd	3	4,100	12,300	\$ 1,100,000	\$ 268.29	1 fiber, 2 copper cables, and 1 SA1. Existing cable is buned for 1500' and 2600' aerial. Job is in progress. Estimated final costs.
Elkton, Main Street	2	2,500	5,000	\$ 900,000	\$ 360.00	Job has been considered by the Town of Elkton for years and is estimated from preliminary plans. Job is still proposed. Very difficult conditions, extensive service drop and terminal work.
Wicomico County, Quantico	1	3,500	3,500	\$ 250,000	\$ 69.44	Job is proposed. Estimated costs.
Totals	41	38,200	223,594	\$ 8,480,692		
Averages across 10 jobs	4	3,820	22,359	\$ 848,069	\$ 222.01	
Average cost per mile					\$ 1,172,200.36	

CN 8826 Selective Undergrounding Working Group

Response from the Baltimore Gas & Electric Company

Costs to Improve Reliability

1. Select an overhead feeder identified by your company for focused/special/reliability-driven maintenance. This feeder must have at least 12 months of outage history AFTER the focused/special/reliability-driven maintenance was completed.

Erdman Substation, Feeder #7027 – this circuit was targeted for our overhead inspection and maintenance (OH I&M) program for March of 1996. It serves 2344 residential and small commercial customers in the Bowley's Lane area of northeast Baltimore City.

2. Provide SAIFI and SAIDI, as defined in IEEE P1366/D19, for the feeder for the 12 months preceding the start of the focused/special/reliability driven maintenance. Provide the indices for all weather events as well as without major storms.

Performance was as follows:

<u>Weather</u>	<u>Time Period</u>	<u>SAIFI</u>	<u>CAIDI</u>	<u>SAIDI</u>
All Weather	12 months prior to OH I&M	1.31	204	267
	12 months after OH I&M	0.08	125	10
Excluding Major Storms	12 months prior to OH I&M	0.97	133	129
	12 months after OH I&M	0.07	114	8

3. Summarize the focused/special/reliability-driven maintenance done on the feeder and provide the total cost. Include when the maintenance was initiated and when it was completed.

Our Targeted Overhead Inspection & Maintenance Program includes a full inspection of the entire circuit, replacement of any broken or defective parts including known substandard performing components, fuse coordination review, application of wildlife protection, fusing of unfused taps or transformers, additional fusing to better sectionalize taps, application of additional lightning arrestors, and identification of required tree trimming. The maintenance was initiated and completed in March of 1996. The approximate cost of this work was \$26,000.

4. Provide SAIFI and SAIDI, as defined in IEEE P1366/D19, for the feeder for 12 months after the start of the focused/special/reliability driven maintenance. Provide the indices for all weather events as well as without major storms.

See question #2.

5. Provide a cost estimate to underground the feeder, specifying whether construction is looped or radial. Provide a reasonable break-down of costs into categories, including costs to remove overhead facilities

Approximately \$10,000,000 total. The construction would be primarily looped on the mains (having ties to other feeders) but radial on the laterals. This would break down into about \$3,000,000 in service conversions, \$3,000,000 for primary cable, \$1,500,000 for secondary voltage cable, \$1,000,000 for equipment such as transformers and switchgear, and \$1,500,000 for removing the overhead and restoring the sidewalks and streets.

Reliability of Overhead vs. Underground

1. Select two feeders, one primarily overhead and one primarily underground in close geographic proximity to each other. If you can query your outage records to a finer level, pick two communities.

We looked at several pairs of feeders. The circuit pair chosen is most representative of the average performance levels of all the pairs of feeders.

Joppatowne Substation, Feeder # 7075 – This circuit travels north from the substation to Philadelphia and Mountain Roads, serving a mixture of older and newer residential customers from mostly overhead lines.

Joppatowne Substation, Feeder # 7071 – This circuit travels south from the substation, serving primarily newer residential customers from mostly underground lines.

2. Provide SAIFI and SAIDI, as defined in IEEE P1366/D19, for the feeders or communities for each of the past three calendar years. Provide the indices for all weather events as well as without major storms.

Circuit #	Weather	SAIFI			SAIDI		
		1997	1998	1999	1997	1998	1999
7075 (OH)	All	3.43	0.45	7.96	65	242	680
	Excl. Major	3.43	0.45	3.84	65	242	151
7071 (UG)	All	0.58	1.72	1.39	178	94	118
	Excl. Major	0.58	1.72	1.39	178	94	118

3. Include a detailed enough description of the location and composition of the feeders to be convincing that they are comparable.

See # 1.

Conversion Cost Data

Provide cost information on a recent overhead to underground conversion project. If possible, use a project that represents a mid-range in cost. Include other utility costs (Bell Atlantic, CATV), as appropriate.

Gateway Circle Project in Annapolis:

In 1996 the City of Annapolis and BGE began working on a project to underground the electric facilities at the intersection of West Street, Taylor Avenue and Spa Road in Annapolis. The undergrounding was performed in conjunction with a road realignment project including a new traffic circle, which required the relocation of our overhead lines. The City agreed to pay the incremental cost between relocating the lines overhead and relocating the lines underground. The cost to relocate the lines overhead would have been about \$175,000 for roughly 5,500 feet of circuit. The underground cost was about \$800,000. The City built, owns and maintains the duct bank for this job, so the costs stated are less than what would be expected in similar circumstances elsewhere.

Historic District Project in Annapolis:

In response to a study by the Fire Safety Commission following a fire on Main Street and State Circle in Annapolis in December of 1997, BGE was asked to estimate costs to underground the Historic District of Annapolis. The area reviewed consisted of approximately 4 miles of City streets, 200 utility poles, 160 transformers, and over 600 services. The estimated costs were \$13,680,500 for the entire project. This includes over \$1,100,000 in service conversions, over \$6,200,000 in underground wiring, \$1,750,000 in underground equipment vaults, \$1,425,000 in equipment, over \$600,000 in engineering design and project management, \$375,000 in outdoor lighting, and \$2,000,000 for a variety of items including removing the overhead lines, making street restorations, and sidewalk repairs. While this entire project has not been completed, some components have. The results of that work were reported at the Governor's Task Force, including one portion less than a mile in length that cost in excess of \$4,000,000 for the electric lines to be relocated underground. This portion, I recall, was estimated to cost about \$400,000 for the relocation of the Bell Atlantic lines to underground.

CN 8826 Selective Undergrounding Working Group
Choptank Electric Cooperative Response

Costs to Improve Reliability

1. Select an overhead feeder identified by your company for focused/special/reliability-driven maintenance. This feeder must have at least 12 months of outage history AFTER the focused/special/reliability-driven maintenance was completed.

Choptank has not done any formally focused reliability-driven maintenance. All circuits are routinely maintained through normal operation. For example, if a circuit experiences an outage, it will be patrolled to find a cause and make repairs. For overhead circuits, current weather conditions often suggest possible causes. For example, thunderstorms suggest lightning, windy days suggest right-of-way problems, and good weather suggests vehicles, animals, or material failures. Once, the problem is found, the appropriate crews will make temporary and/or full repairs.

Choptank currently has a very active right-of-way maintenance program. It's biggest material problems are underground cable (HMWPE) failures and the decay of small copper conductors (6 CWC and 8 CWC). Choptank is actively replacing both underground cable and aging small copper conductors as a proactive approach to system maintenance. Line sections are selected based on the number of customers affected, age and number of failures of the existing conductor, and the distance to the nearest district office (speed of repair). This replacement is the majority of Choptank's maintenance program.

2. Provide SAIFI and SAIDI, as defined in IEEE P1366/D19, for the feeder for the 12 months preceding the start of the focused/special/reliability driven maintenance. Provide the indices for all weather events as well as without major storms.

See question #1.

3. Summarize the focused/special/reliability-driven maintenance done on the feeder and provide the total cost. Include when the maintenance was initiated and when it was completed.

See question #1.

4. Provide SAIFI and SAIDI, as defined in IEEE P1366/D19, for the feeder for 12 months after the start of the focused/special/reliability driven maintenance. Provide the indices for all weather events as well as without major storms.

See question #1.

5. Provide a cost estimate to underground the feeder, specifying whether construction is looped or radial. Provide a reasonable break-down of costs into categories, including costs to remove overhead facilities.

See question #1.

Reliability of Overhead vs. Underground

1. Select two feeders, one primarily overhead and one primarily underground in close geographic proximity to each other. If you can query your outage records to a finer level, pick two communities.

Choptank chose two feeders from its Hillsboro Substation. Circuit 313 is 80% overhead and averages about 25 years old. Circuit 312 is approximately 90% underground and was initially installed underground with poor quality HMWPE cable in the early 80's. The majority of the cable had to be replaced during 1988-1993.

2. Provide SAIFI and SAIDI, as defined in IEEE P1366/D19, for the feeders or communities for each of the past three calendar years. Provide the indices for all weather events as well as without major storms.

<u>Circuit #</u>	<u>SAIFI</u>		
	<u>1996</u>	<u>1997</u>	<u>1998</u>
313 (OH)	0.035	0.058	0.039
312 (UG)	0.048	0.053	0.055

Choptank's outage system has only tracked SAIFI in the past, however, a new system will provide SAIFI, SAIDI, and CAIDI in the future.

3. Include a detailed enough description of the location and composition of the feeders to be convincing that they are comparable.

See question #1.

Conversion Cost Data

Provide cost information on a recent overhead to underground conversion project. If possible, use a project that represents a mid-range in cost. Include other utility costs (Bell Atlantic, CATV), as appropriate.

Choptank has not completed any conversions to underground in recent years. In fact, Choptank has converted back to overhead where possible, particularly on multi-phase lines to reduce the expense associated with sectionalizing enclosures and other padmounted switchgear. Choptank's conversion costs for a 3 phase feeder range from \$300,000 to \$500,000 per mile. This does not include the costs for other utilities which may be located

on the poles. In the past, Choptank has normally turned over ownership of the pole to one of the remaining utilities.

**CN 8826 Selective Undergrounding Working Group
Requested Data for 1/20/2000 Meeting
Conectiv Response**

Costs to Improve Reliability

Request

1. Select an overhead feeder identified by your company for focused/special/reliability-driven maintenance. This feeder must have at least 12 months of outage history AFTER the focused/special/reliability-driven maintenance was completed.
2. Provide SAIFI and SAIDI, as defined in IEEE P1366/D19, for the feeder for the 12 months preceding the start of the focused/special/reliability driven maintenance. Provide the indices for all weather events as well as without major storms.
3. Summarize the focused/special/reliability-driven maintenance done on the feeder and provide the total cost. Include when the maintenance was initiated and when it was completed.
4. Provide SAIFI and SAIDI, as defined in IEEE P1366/D19, for the feeder for 12 months after the start of the focused/special/reliability driven maintenance. Provide the indices for all weather events as well as without major storms.
5. Provide a cost estimate to underground the feeder, specifying whether construction is looped or radial. Provide a reasonable break-down of costs into categories, including costs to remove overhead facilities.

Conectiv Response

District Engineering reports that reliability improvements were completed on Fruitland 2266, 25 kV feeder in January 1999. This feeder serves about 3,478 customers. The reliability improvements included converting a section from underground to overhead. About 1 mile of underground cable located 1.5 miles from the substation was abandoned due to multiple failures. The 750 kCMIL cable originally installed about 25 years ago for aesthetics and due to a nearby airport was not repairable. An aerial circuit was rebuilt to serve the area from another route at a cost of about \$90,000.

This feeder, Fruitland 2266, is about 15 miles long serving the southern end of Salisbury. The customers on the feeder include Salisbury State University, light commercial, and residential. The residential is largely composed of 35 year old communities and comprises about 50% of the feeder. A very rough estimate to underground this feeder would amount to \$10 million plus restoration costs based on the 15 mile length and a unit cost of \$136/foot. A more detailed estimate is not available within the time frame requested.

With Storms		1999		1998	
Substation	Feeder ID	SAIFI	SAIDI	SAIFI	SAIDI
Fruitland	2266	1.43	54.90	3.274	213.16

Without Storms		1999		1998	
Substation	Feeder ID	SAIFI	SAIDI	SAIFI	SAIDI
Fruitland	2266	1.43	54.90	2.359	145.12

Reliability of Overhead vs. Underground

Request

1. Select two feeders, one primarily overhead and one primarily underground in close geographic proximity to each other. If you can query your outage records to a finer level, pick two communities.
2. Provide SAIFI and SAIDI, as defined in IEEE P1366/D19, for the feeders or communities for each of the past three calendar years. Provide the indices for all weather events as well as without major storms.
3. Include a detailed enough description of the location and composition of the feeders to be convincing that they are comparable.

Conectiv Response

District Engineering selected two 25 kV feeders from North Salisbury Substation. North Salisbury 2284 exits the substation underground, continues underground for two miles feeding an industrial park, and then continues with portions overhead and underground feeding commercial and residential customers. North Salisbury 2254 is an overhead feeder almost in parallel with feeder 2284 but it does not feed the industrial park. Feeder 2284 serves about 303 customers and 2254 about 2,130 customers.

With Storms		99 (as of 11/99)		98		97	
Substation	Feeder ID	SAIFE1	SAIDI	SAIFE1	SAIDI	SAIFE1	SAIDI
North Salisbury	2254	0.400	47.81	0.328	24.18	2.935	230.84
North Salisbury	2284	0.205	18.59	1.465	129.61	1.333	18.16

Without Storms		99 (as of 11/99)		98		97	
Substation	Feeder ID	SAIFE1	SAIDI	SAIFE1	SAIDI	SAIFE1	SAIDI
North Salisbury	2254	0.343	44.30	0.289	23.48	1.844	129.04
North Salisbury	2284	0.205	18.59	1.465	129.61	1.252	11.8

Conversion Cost Data

Request

Provide cost information on a recent overhead to underground conversion project. If possible, use a project that represents a mid-range in cost. Include other utility costs (Bell Atlantic, CATV), as appropriate.

Conectiv Response

The one project that comes to mind is the City of Ocean City sponsored project to underground parts of the city. This is **not** a typical project due to the terrain and nearly all of the customers are commercial type accounts. The city performed all of the trenching and installed conduit and foundations for all utilities. The city also did all of the restoration work and reimbursed the utilities for their work. The most recent section was seven blocks long or about 1,500 to 2,000 feet and included undergrounding all electric facilities. This consisted of a single primary, 12 kV circuit, secondaries, services, street lights, and removal of the overhead facilities, and was completed in December 1998. The Conectiv portion of the cost amounted to \$600,000, which was paid by the city. The \$600,000 does not include the work done directly by the city to facilitate this project, such as, installation of the conduit.

The total Ocean City project encompasses some 18 blocks (approximately 3000 feet – estimated total Conectiv cost = \$951,000 for undergrounding lateral loops services only. An additional \$500,000 or more would be required to also underground the main circuit in the vicinity) and includes parts of the circuits listed below with reliability data noted:

With Storms		99 (as of 11/99)		98		97	
Substation	Feeder ID	SAIFI	SAIDI	SAIFI	SAIDI	SAIFI	SAIDI
Maridel	421	2.105	173.9	0.057	2.6	0.067	4.7
		0.75	4.8				
Ocean City	426	0.075	14.3	0.056	6.1	0.138	5.8
		0.01	1.74				

Without Storms		99 (as of 11/99)		98		97	
Substation	Feeder ID	SAIFI	SAIDI	SAIFI	SAIDI	SAIFI	SAIDI
Maridel	421	1.037	57.40	0.057	2.6	0.065	4.6
		0.02	1.51				
Ocean City	426	0.074	14.3	0.049	5.73	0.108	3.2

The change in reliability data in 1999 is due mostly to higher than normal outages caused salt contamination of the overhead portion of the line. For 1999, the top number indicates indices with salt contamination outages included. The bottom number indicates indices with the salt contamination outages excluded.

Data provided by Earl Robinson & Lisa Fincher. Compiled by Bob Rogers, Conectiv Distribution Design, January 19, 2000 Revision 1

Potomac Electric Power Company Power Distribution

Cost To Improve Reliability on Distribution Feeder

Construction						Outage History						Cost For Underground Alternative
Feeder Number	Sub Number	Description of Work Performed	Number of Services	Actual Cost	Construction Date	Previous Year			Following Year			
						Data Year	Feeder SAIDI	Feeder SAIFI	Data Year	Feeder SAIDI	Feeder SAIFI	
15108	#192 Longwood	Replaced existing bare wire with 32559' of tree wire installed seven (7) motor operated switches (3 on 15107, 4 on 15108)	2,621	\$441,895	1998	1997	9,5903	7,1131	1999	0,4664	0,0985	\$4,000,000
15107			11,429			1997	7,6624	9,5572	1999	0,7563	0,1679	

NOTE:
SAIDI and SAIFI are calculated excluding major storms

Cost To Improve Reliability on Distribution Feeder

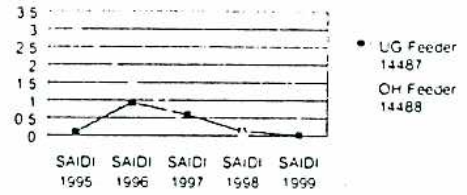
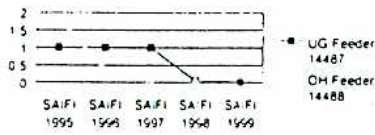
Construction						Outage History					
Feeder Number	Sub Number	Description of Work Performed	Number of Services on Feeder	Actual Cost	Construction Date	Previous Year			Following Year		
						Data Year	Feeder SAIDI	Feeder SAIFI	Data Year	Feeder SAIDI	Feeder SAIFI
14973	#20 Potomac	Remove existing overhead line and install 4000' of URD cable within Potomac Falls Estates DWG 8511068 *	627	\$1,500,000	February 1998	1997	7,3290	3,5500	1998	0,8540	0,2250

NOTE:
SAIDI and SAIFI are calculated excluding major storms

Potomac Electric Power Company Power Distribution

Area	Substation	Sub No	Feeder	% CF Service	1995		1996		1997		1998		1999	
					SAIFI	SAIDI	SAIFI	SAIDI	SAIFI	SAIDI	SAIFI	SAIDI	SAIFI	SAIDI
MC	Fairfax	177	14487	84 UG	1.0000	0.0833	1.0000	0.9258	1.0000	0.5750	0.6584	0.1227	0.3022	0.0150
			14488	70 OH	1.7913	3.0221	0.3520	1.5080	0.1204	0.3015	0.0321	0.1054	0.2475	0.1895

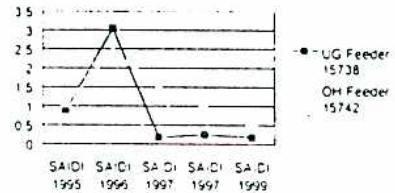
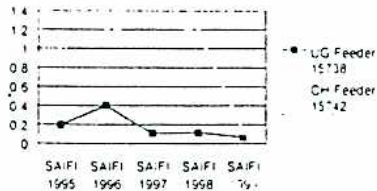
SAIFI Representation For Underground Vs. Overhead Feeders



Note

Both Feeders are supplied from the same Substation and extended in Montgomery County within Silver Spring area
Feeder 14487 is approximately 84% Underground
Feeder 14488 is approximately 70% Overhead

Area	Substation	Sub No	Feeder	% CF Service	1995		1996		1997		1998		1999	
					SAIFI	SAIDI	SAIFI	SAIDI	SAIFI	SAIDI	SAIFI	SAIDI	SAIFI	SAIDI
PG	Greenbelt	173	15738	86 UG	0.1942	0.8836	0.3984	3.0351	0.1043	0.1751	0.1126	0.2438	0.0651	0.1765
			15742	71 OH	1.1266	1.0679	1.1671	2.4142	1.2979	1.4806	1.1221	0.954	0.1422	0.5944

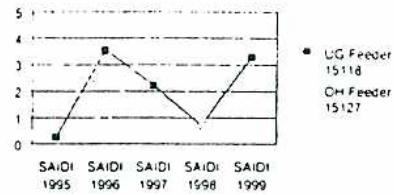
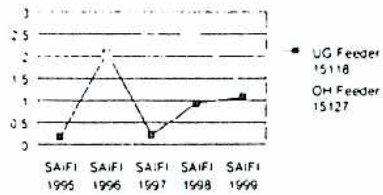


Note

Both Feeders are supplied from the same Substation and extended in Prince George County within Greenbelt area
Feeder 15738 is approximately 86% Underground
Feeder 15742 is approximately 71% Overhead

Potomac Electric Power Company Power Distribution

Area	Substation	Sub No	Feeder	% OF Service	1995		1996		1997		1998		1999	
					SAIFI	SAIDI	SAIFI	SAIDI	SAIFI	SAIDI	SAIFI	SAIDI	SAIFI	SAIDI
MC	Norbeck	151	15118	UG	2.1724	3.2527	2.4525	3.5211	2.2214	2.2249	2.2214	0.709	1.2551	1.2582
			15127	OH	2.2362	3.0839	2.0703	0.5853	3.5935	4.5477	2.4295	0.7483	1.7145	4.3351



Note

Both Feeders are supplied from the same Substation and extended in Montgomery County within Norbeck area
 Feeder 15118 is approximately 79% Underground
 Feeder 15127 is approximately 51% Overhead

**1998 AND 1999
UNDERGROUND CABLE DIG-IN COUNTS
AS COMPILED BY THE
SELECTIVE UNDERGROUND WORKING GROUP FOR THE
MARLAND PUBLIC SERVICE COMMISSION**

UTILITY	1998 UNDERGROUND DIG-INS	1999 UNDERGROUND DIG-INS	2-YEAR AVERAGE UNDERGROUND DIG-INS
ALLEGHENY POWER	68	104	86
BGE	858	832	845
PEPCO	522	610	566
CONNECTIV	66	69	68
TOTALS	1514	1615	1565