REPORT OF THE
STATE CORPORATION COMMISSION

Placement of Utility Distribution Lines Underground

TO THE GOVERNOR AND
THE GENERAL ASSEMBLY OF VIRGINIA

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This report provides information on the feasibility of placing underground the currently existing overhead utility distribution lines and any new distribution lines, the costs that would be incurred, and the options for funding such underground placement.

Respectfully submitted,

Theodore V. Morrison, Jr.
Commission Chairman

Clinton Miller
Commissioner

Mark C. Christie
Commissioner

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EXECUTIVE SUMMARY

House Joint Resolution No. 153 of the 2004 Regular Session of the Virginia General Assembly requested the State Corporation Commission to study the feasibility, costs and funding options relative to the placement of currently existing overhead utility distribution lines, and any new distribution lines, underground. The resolution was passed in anticipation that placing distribution lines underground (1) would reduce the number of weather-related utility disruptions, (2) may reduce utility line maintenance costs, and (3) would minimize the visual pollution in the Commonwealth. In the conduct of this study, participation of interested parties was solicited and various state and international studies were reviewed.

The primary advantages of underground circuits are improved aesthetics and overall improved reliability. In addition, underground rights-of-way require little tree trimming and underground facilities are much less susceptible to motor vehicle accidents. However, the relocation of currently existing overhead lines would result in tremendous costs and significant disruptions. In addition, a major relocation initiative could take decades to complete and encounter complications regarding underground damage prevention and attainment of new easements.

The cost associated with the placement of the currently existing overhead electric utility distribution facilities underground was estimated by utilities to be over $80 billion. The resultant annualized revenue requirement on a per customer basis would be approximately $3,000. The additional cost to bury existing overhead telecommunications and cable television lines was estimated to be approximately $11 billion.

The potential benefits, both to the utilities and to the economy, resulting from the elimination of tree trimming maintenance, vehicle accidents, post storm restoration and lost sales during outages, do not appear to be sufficient to offset the initial construction costs associated with a comprehensive program to relocate the currently existing overhead utility distribution lines to underground. The placement of all new distribution lines underground, though not as costly, is also probably not cost effective.

Regardless of the funding options available for a comprehensive statewide initiative, the costs would be paid ultimately by consumers, either directly or indirectly, in the form of prices, taxes, or utility rates. Anecdotal evidence suggests that consumers might not be willing to pay the costs necessary to fund a comprehensive statewide initiative.

Based on our research and analysis and input from interested parties, the wholesale relocation of the currently existing overhead utility distribution lines and placement of all new utility distribution lines underground is probably not reasonable. The economic effects of such an effort on state and local governments or utilities, and ultimately consumers, would be significant. Recent studies by the Public Staff of the North Carolina Utilities Commission, the Maryland Task Force to Study Moving Overhead Utility Lines Underground, and the Edison Electric Institute support these conclusions.

While a comprehensive statewide relocation initiative does not appear to be reasonable from an economic viewpoint, certain localities and their citizens might value the aesthetic benefits enough to be willing to plan, implement and fund a local undergrounding initiative. It appears that localities can require the placement of new distribution lines underground, but it is not clear if they have the authority needed to mandate the relocation of existing overhead lines underground.

BACKGROUND AND INTRODUCTION

House Joint Resolution No. 153 (see Appendix A) of the 2004 Regular Session of the Virginia General Assembly ("HJR153" or "Resolution") requested the State Corporation Commission ("SCC" or "Commission") to study the placement of utility lines underground. Specifically, HJR153 directed the Commission to "solicit the participation of interested parties in conducting a study of the feasibility of placing underground the currently existing overhead utility distribution lines and any new distribution lines, the costs that would be incurred, and the options for funding such underground placement." Furthermore, the Resolution specified that an executive summary and a progress report be submitted to the Division of Legislative Automated Systems no later than the first day of the 2005 Regular Session of the General Assembly. The Commission has completed the study and presents this report in accordance with the requirements of the Resolution.

In the conduct of the feasibility study, the Commission Staff ("Staff") solicited comments on July 16, 2004, to a set of generic questions from interested parties and convened a kickoff meeting of the interested parties on August 16, 2004. In addition, the Staff created a web site to accept comments from the general public, surveyed a group of consumers regarding their willingness to pay for conversion[1] of overhead facilities to underground, developed and submitted formal data requests to the electric utilities and telecommunications providers, and reviewed reports of previous studies on the feasibility of placing electric distribution facilities underground. In addition to analyzing cost data for the statewide conversion of overhead facilities to underground, the Staff also organized a case study of the costs associated with a specific project – the conversion of an overhead circuit serving commercial and residential accounts along Ocean View Avenue in the City of Norfolk.

Based on the Staff's analysis and input from interested parties, the wholesale relocation of the currently existing overhead utility distribution lines and placement of all new utility distribution lines underground is probably not reasonable. The economic effects of such an effort on state or local governments, or utilities – and ultimately consumers – would be significant. On the other hand, the placement of new distribution lines underground in many applications is common practice and can be accomplished pursuant to existing Commission approved tariffs. Though less common, utilities will relocate overhead distribution lines according to company policies and/or tariffs.

The focus of, and main conclusions relative to, this report result primarily from the expansive scope of the study and broad analysis of the issues as defined by the Resolution. To the extent state or local governing entities determine that formal, systematic policies and programs for undergrounding distribution lines on a limited and/or local level should be pursued, some additional important issues beyond the scope of this report might need to be addressed. First, each specific project or program should be evaluated on its own merits and a determination made as to whether or not

[1] Although some utilities assign different meanings to "conversion" and "relocation," the terms are used interchangeably in this report.

undergrounding of specific distribution lines is in the public interest, given consumers' perceived weighting of the costs and benefits associated with placing lines underground. In some instances in other states, this responsibility has been assigned directly to consumers through the use of surveys or by popular vote. Second, the funding options and financing arrangements specific to a particular application or circumstance will need to be analyzed and the preferred options designated. Again, this could be dependent, in part, on consumer preferences as well as the size of the undergrounding projects to be undertaken. Finally, other important issues that would need to be addressed, either at the state or local level, include defining the role, if any, of utilities in improving the visual environment in the state, developing the criteria used to prioritize multiple undergrounding projects, and establishing a schedule for completion of such projects.

This introduction is followed by an explanation of the interested parties' participation in the study. Following that explanation, descriptions of overhead and underground power delivery systems, overhead and underground telecommunications and cable television ("CATV") service delivery systems, and the process for converting overhead distribution facilities to underground are provided. Discussions of the costs and benefits associated with undergrounding are provided in six sections that include, in order, the following topics: the identification of the costs and benefits, a utility-related cost/benefit analysis, a case study of an individual circuit, an analysis of the potential benefits to the economy, a summary review of the economic costs and benefits, and a discussion of additional impacts and feasibility issues. The final five sections include conclusions of previous studies; findings regarding the feasibility, costs and benefits, and funding options related to undergrounding; and, finally, the summary, conclusions and recommendations.

PARTICIPATION OF INTERESTED PARTIES

As mentioned in the *Background and Introduction* of this report, HJR153 directed the Commission to "solicit the participation of interested parties" in conducting this feasibility study. In order to accomplish this, in part, the Commission Staff issued a press release and created a web site to request and accept comments from the general public. Notice was also published in the Virginia Register of Regulations. As part of its invitation to the public to comment on the feasibility study, the Commission requested that comments address the potential benefits, costs and obstacles associated with converting overhead distribution lines to underground, as well as identify potential funding options and criteria for prioritizing individual circuits.

The Commission received comments from approximately 115 residential consumers. With respect to these respondents' electric service providers, approximately 105 (91%) were served by Dominion Virginia Power, 7 (6%) were served by Appalachian Power Company, and 3 (3%) were served by electric cooperatives.

The Commission also received a resolution and several letters from various local government representatives and two civic associations in response to its invitation for comments. Comments were received from the Madison Manor Civic Association (Arlington County), Great Falls Citizens Association, Arlington County Board, Colonial

Heights City Council, Danville City Manager, Hampton Roads Planning District Commission, New Kent County Department of Community Development, City of Norfolk Department of Public Works, Norfolk Redevelopment and Housing Authority, City of Roanoke Department of Public Works and the Staunton City Manager. Comments were also submitted by the Energy Issues Chair of the Sierra Club Virginia Chapter. Summaries of the public comments and the letters, emails and resolutions from government entities and the Sierra Club, are provided in Appendix B.

The Staff also solicited responses to a set of generic questions from approximately 65 interested parties and convened a kickoff meeting for these same interested parties. The following 13 entities provided a response to the generic questions: Arlington County, City of Fairfax, Home Builders Association of Virginia, The Virginia Cable Telecommunications Association, Shenandoah Telephone Company, Sprint, Verizon, Virginia-Maryland-Delaware ("VMD") Association of Electric Cooperatives, Allegheny Power, Appalachian Power Company, Conectiv Power Delivery, Dominion Virginia Power, and Old Dominion Power Company. The generic questions and aggregate summaries of the responses are provided in Appendix C.

The electric utility organizations represented at the kickoff meeting included the following: Allegheny Power, Appalachian Power Company, Old Dominion Power Company, Pepco Holdings, Inc., Dominion Virginia Power, VMD Association of Electric Cooperatives, Northern Virginia Electric Cooperative, Rappahannock Electric Cooperative, Southside Electric Cooperative, and Shenandoah Valley Electric Cooperative. The telecommunications organizations included Cox Virginia Telecom, Shenandoah Telephone Company, Sprint, Verizon Virginia, Inc., the Virginia Telecommunications Industry Association, and the Virginia Cable Telecom Association. The municipalities and related entities included County of Arlington, County of Fairfax, City of Norfolk, City of Richmond, Virginia Association of Counties, and the Virginia Municipal League. Other organizations included the Home Builders Association of Virginia, Northern Virginia Building Association, and Virginia Farm Bureau. State agencies attending included the Virginia Attorney General's Office and the Virginia Department of Transportation.

The Staff also surveyed a group of residential consumers regarding their willingness to pay for conversion of overhead facilities to underground, developed and submitted formal data requests to the electric utilities and telecommunications providers, and consulted with groups of interested parties regarding specific issues. The results of these efforts are addressed elsewhere in the report.

OVERHEAD AND UNDERGROUND POWER DELIVERY SYSTEMS[2]

The Electric Utility Distribution System

The electric utility system is usually divided into three systems: generation,[3] transmission,[4] and distribution.[5] Electric power produced at generating stations is transported across high-voltage transmission lines to distribution substations near major load centers. At the distribution substations, transformers reduce the voltage for delivery to consumers over lower voltage distribution lines and equipment ("facilities"). It is the distribution system that is the subject of this feasibility study.

The distribution system is commonly divided into three segments: distribution substations, primary voltage facilities, and secondary voltage facilities. Primary voltage facilities typically include (a) the three-phase feeders (or "mains" or "backbones") exiting the substation, (b) the three-, two-, or single-phase tap (or "branch") lines that tap off the main feeder, and (c) distribution (or "service") transformers, which lower voltage from the primary distribution voltage to secondary (or "utilization" or "customer") voltages. Secondary voltage facilities include the service lines which lead directly to a customer's meter ("laterals," if underground, or "drops," if overhead).

Overhead Distribution Systems

Overhead distribution systems are usually operated in a radial configuration.[6] The poles that carry the primary distribution conductors ("wires") generally carry only one primary circuit; however, additional primary circuits are occasionally strung for some distance. In addition, secondary circuits are sometimes run underneath the primary circuit. Most distribution utility poles are wood, although other materials, such as steel or concrete, are also used.

Pole mounted distribution transformers supply secondary voltage for the overhead service drops to customers. Service drops are typically "triplex," which consist of two insulated conductors wrapped around a weight-bearing bare neutral conductor. Electric utilities rent space on their poles to telecommunications or cable television ("CATV") companies that string their lines underneath the electric power lines.

Overhead construction costs can range from $10,000 per mile to $250,000 per mile, depending on circumstances such as labor costs, terrain, and conductor size. Suburban three-phase mains typically cost $60,000 to $150,000 per mile; single-phase

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[2] The discussion in this section is taken largely from the following four references:
The Changing Structure of the Electric Power Industry 2000: An Update, DOE/EIA, October 2000; T.A. Short (EPRI PEAC), *Electric Power Distribution Handbook*, CRC Press, Washington, D.C., 2004; H. Lee Willis (ABB Power T&D Company Inc.), *Power Distribution Planning Reference Book*, 1997; James J. Burke (Power Technologies, Inc.), *Power Distribution Engineering*, Marcel Dekker, Inc., 1994.

[3] Generation is the process of producing electrical energy from other forms of energy.

[4] Transmission is the act or process of transporting electric energy in bulk from a source or sources of supply to other principal parts of the system or to other utility systems.

[5] Distribution is the act or process of delivering electric energy from convenient points on the transmission or bulk power system to consumers.

[6] In a radial configuration, electrical power flows away from the substation to the customer along a single path, which, if interrupted, results in complete loss of power to the customer.

taps $40,000 to $75,000 per mile. These cost ranges are typical in Virginia as well. Construction is normally less expensive in rural areas. In Virginia, the five investor-owned electric utilities[7] own a total of approximately 63,000 miles of overhead distribution lines.[8] The state's 13 electric cooperatives have approximately 35,000 miles of overhead distribution lines.[9]

Underground Distribution Systems

Much new distribution is now being placed underground, especially for taps in suburban residential areas. Whether urban, suburban, or even rural, all parts of a distribution circuit can be underground, including the main feeder. Underground conductors are generally referred to as "cables." Underground residential distribution ("URD") primary circuits are typically built in a loop arrangement which is fed from each end by an overhead circuit;[10] however, utilities sometimes use radial circuits or circuits with radial taps or branches.

A secondary underground network ("grid") configuration is used in the downtown areas of most major cities. In grid networks, the secondary services are networked together and fed from several primary distribution circuits, normally originating from one substation. Secondary networks are very reliable, since if any of the primary distribution circuits fail, the others will carry the load without causing an outage for any customers.

In suburban or rural URD areas, insulated cable (with or without conduit) typically is placed in open trenches. In urban commercial areas, cables are normally installed in concrete-encased duct banks beneath streets, sidewalks, or alleys.

Circuits are seldom totally underground; the portion nearest the substation is usually overhead. The interface between the overhead portions of a circuit and the underground portions of a circuit is the "riser pole."

New underground construction costs can range from $40,000 per mile to $1.5 million per mile. Converting existing overhead facilities to underground would cost significantly more. The main factors that influence underground costs are the extent of community development, soil conditions, and burial method.

In Virginia, the five investor-owned electric utilities maintain approximately 21,000 miles of underground distribution cable, of which 16,639 miles are owned by Virginia Power. Approximately 35 percent of Virginia Power's distribution lines are

[7] Virginia Electric and Power Company d/b/a Dominion Virginia Power ("DVP" or "Virginia Power"); Appalachian Power Company d/b/a American Electric Power – Virginia ("APCo" or "Appalachian Power"); Potomac Edison Company d/b/a Allegheny Power Company ("Potomac Edison"); Delmarva Power & Light Company d/b/a Conectiv ("Delmarva Power"); Kentucky Utilities d/b/a Old Dominion Power Company.

[8] Based on 2003 statistics. The 63,000 miles is approximately 75 percent of all overhead and underground distribution lines owned by the investor-owned utilities.

[9] Based on 2002 data for 12 cooperatives and 2000 data for Craig-Botetourt Electric Cooperative.

[10] A loop arrangement provides each pad mounted distribution transformer with a normal, and an alternate, power source through the primary cable. Pad mounted transformers on the ground are used to lower the primary voltage to secondary voltage for delivery to individual customers.

underground. For Delmarva Power, Potomac Edison, APCO, and Old Dominion Power, the percentages are 32, 13, 11, and 1, respectively.

Overhead vs. Underground

Both overhead and underground distribution facilities are commonplace in the United States, in general, and in many areas of Virginia, in particular. Most utilities today put much of their single-phase system underground in new residential developments, while multi-phase systems remain largely above ground. Some utilities and/or municipalities are also very slowly converting some existing overhead distribution facilities to underground.

In 2003, Virginia Power installed approximately 96 percent of its new residential services underground. APCO installed nearly 70 percent of its new residential services underground, while Delmarva Power reported installing 50 percent of its new residential services underground. Potomac Edison installed approximately 85 percent of its suburban and 50 percent of rural residential services underground. However, Old Dominion Power placed only 13 percent of its rural residential services and 8 percent of its suburban residential services underground. The electric cooperatives that provided data reported installing a significant percentage of residential services underground in 2003.[11] In some jurisdictions, significant amounts of single-phase tap lines are also being placed underground, but very few multi-phase lines are being placed underground in Virginia.

Both designs have advantages; however, the major advantage of overhead distribution circuits in most cases is significantly lower initial construction costs.[12] In addition, individual faults on overhead circuits can be repaired more quickly than on underground circuits, and some experts believe that overhead circuits have a longer life. Early underground residential circuits failed at a much higher rate than expected, but experts now believe that new underground circuits will last at least 30 years, while overhead circuits will last 40 years or greater. Overhead circuits also have some operational advantages because they have more flexibility with respect to circuit reconfiguration and can more readily withstand overloads.

The primary advantages of underground circuits are improved aesthetics and overall improved reliability. With respect to aesthetics, while underground circuits are more appealing in the long term, initial underground construction activities can be untidy. With respect to reliability, although a specific fault on an underground circuit might take longer to locate and repair, underground systems fail less often and the average customer outage time (averaged over all customers) should be less for most underground systems. Undergrounding also eliminates most momentary interruptions.

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[11] NNEC (95% of rural residential services); SVEC (75% of rural residential services); REC (90% of suburban residential services, 70% of rural residential services); CEC (70% suburban residential services, 60% rural residential services); NOVEC (95% of suburban residential services, but only 5% of rural residential services); PGEC reported it mainly installs underground residential services.

[12] Under certain conditions, cost estimates of underground cable installations can be less expensive than overhead lines.

Placing distribution facilities underground also virtually eliminates the need for tree-trimming, eliminates vehicular accidents with utility poles, reduces some electrical hazards, and nearly eliminates the need for extensive restoration efforts after catastrophic storms. While other operating and maintenance ("O&M") costs could be higher in some applications, overall O&M costs could decrease as a result of placing facilities underground in some cases.

Whether to place new distribution circuits underground or to convert existing overhead facilities to underground are not all-or-nothing propositions. Hybrid systems – overhead feeders with underground taps or overhead primaries with underground secondaries – exist today. Converting from existing overhead systems to underground systems is costly, but there might be locations and situations where such an effort is suitable for utilities and their customers.

OVERHEAD AND UNDERGROUND TELECOMMUNICATIONS/CATV SERVICE DELIVERY SYSTEMS

The telecommunications and CATV networks are divided into three major components: the telecommunications company central office or CATV head end office, the feeder cables, and the distribution facilities. The telecommunications company central offices are where the subscriber lines are connected to switching equipment designed to connect customers whether making local or long distance calls. The head end office is where the CATV signal originates on the CATV network. The feeder cables in both systems are used for the transmission of voice, video, and data between the central office or head end, access node or remote switch located near the customer. The distribution facilities are generally the smaller or lower capacity facilities located beyond the access nodes and include the service wires that connect to customer premises. Both telecommunications and CATV feeder or main line cables, distribution cables, and service wires would be included in any undergrounding projects.

A typical circuit to serve a customer would involve a host central office or head end office, feeder or tie cable from the host to an access node, distribution cable from the access node to the customer service terminal, and a service wire from the service terminal to the customer premises. These facilities can be copper, fiber optic, coaxial, or various combinations of each. The trend today in provisioning landline telecommunications and information services is towards conversion to fiber optics. This particular trend can be attributed to better economics and increasing customer demand for bandwidth and multiple services like voice, broadband data, and video from a single provider. Existing copper facilities can only support the higher bandwidth requirement for short distances and therefore is causing telecommunications providers to consider replacement of their older facilities. The expected service life of fiber optic cable is longer than that for copper facilities. One company provided expected cable service life estimates for copper cables in the range of 25 to 34 years and fiber optics in the 28 to 40 year range.

In some areas of the state, projects are already under construction to convert entire networks, from the switching centers to the customer's premises, from copper to fiber optics. Access nodes are switches located near the customer and in some network configurations are the connection points where the copper or coaxial distribution cables are connected to the fiber optic fed electronics that serve the customer. In the cases where companies have begun placing fiber optic cables directly from the host office or access node to the end user the need for copper or coaxial cable is completely eliminated. Fiber optic cable is lighter and smaller than the traditional copper cable and the costs for the cable and installation is usually less than for copper. The cost for the electronics that drive the fiber optic light source is the major cost driver for fiber optic loops as well as the customer end terminal equipment. Copper, fiber optic and coaxial cables usually have conductors insulated with plastic, and have metallic shielding, and plastic sheaths to protect it from the weather and induced power influence. Unlike the aerial and underground power cables, there is little difference between aerial and underground telecommunications and CATV facilities in terms of insulation, design, or transmission capability. In contrast, the aerial and underground power cables have significant differences in design and cost. Aerial power conductors are usually bare conductors insulated only by the surrounding air and use glass insulators to protect the supporting structure. The buried power cables require a highly protective insulation to prevent contact with the earth, workers, or the general public.

CONVERSION PROCESS DESCRIPTION

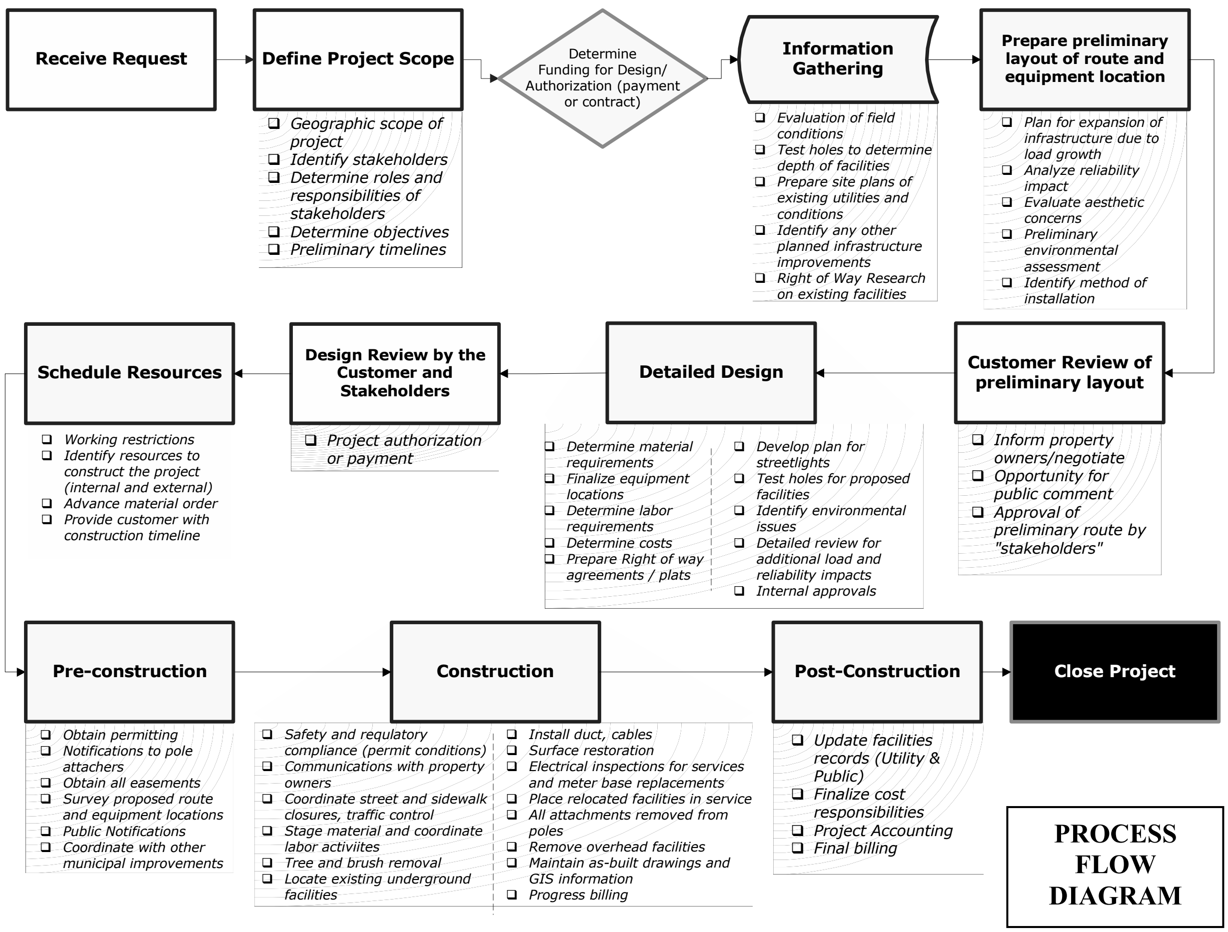
The Staff requested Virginia Power, as an interested party in this feasibility study, to take the lead in the development of a fundamental primer of the burial of distribution facilities for those without first-hand utility design engineering or field experience. An initial draft of the description was circulated for comment to other interested parties who had expressed interest in developing a description of the process, and the final version was edited by the Staff. Although the process described will vary slightly from utility to utility and depending on the terrain and type of community involved, the general concepts are fairly common. A primary purpose of developing this description was to facilitate a conceptual understanding of the magnitude of the costs associated with the conversion of overhead distribution facilities to underground.

The following generic description of the process flow involved in a major overhead-to-underground distribution conversion project is presented from the perspective of an investor-owned electric utility ("utility" or "company"); however, similar processes are used by electric cooperatives and telecommunications providers. This process flow begins with a customer request, continues through a number of sequential steps ("phases"), and ends with the remittance of a final bill to the customer. This process flow, although not all-inclusive, addresses most of the necessary coordination by the company with other utilities, the customer, and federal, state and local governments. It was developed assuming an open trench, concrete (duct bank) encased mainline circuit in an urban area ("conversion project"). This process flow is depicted in seven major phases as follows:

1. Project Scope
2. Preliminary Layout
3. Detailed Design

4. Resource Scheduling
5. Pre-Construction
6. Construction
7. Post-Construction

These seven phases, as well as a number of customer interfaces are discussed in detail in the following paragraphs. Additionally, as a companion to this process description, the following process flow diagram is provided prior to the narrative.[13]



<u>Phase 1 – Project Scope</u>

Once a utility has received a request to underground existing overhead distribution facilities, the company will initiate the process of defining the project scope. The utility will perform an initial evaluation of the geographic boundaries of the area in which a conversion project is to take place. It should be noted that the company would

[13] The initial draft of this process description and the process flow diagram were developed by Dominion Virginia Power.

not perform a land survey at this time, but simply make a preliminary evaluation of the project scope based on the geographic boundaries of the conversion project. For example, the utility will determine whether the conversion project includes secondary lines and services (often located on side streets and alleyways) or whether the scope is limited to the mainline circuit.

The utility will also identify all parties, in addition to the customer, that could have a stake in the conversion project ("stakeholders"). These stakeholders might include state agencies such as the Virginia Departments of Transportation, Conservation and Recreation, and Environmental Quality; numerous agencies within a municipality, county or other political subdivision such as the departments of public works or public utilities; and electrical inspectors and traffic engineers. Other stakeholders include other public utilities such as telecommunications, cable, water and sewer companies. It is at this time, during the project scope phase, that the company and other public utilities will identify any opportunities for joint use of underground trenches, as well as the dismantling of any existing overhead distribution facilities that are jointly used. In addition to the property owners within the geographic scope of the project, property owners in areas adjacent to the conversion project could have a stake in the process. Once the utility has identified the stakeholders, it is imperative that the roles and responsibilities of each is determined and communicated among the stakeholders. Since the process of defining roles and responsibilities typically involves numerous entities, this is best achieved if the process is a collaborative one.

Based on the geographic evaluation and the identification of stakeholder roles and responsibilities, the company will prepare a preliminary timeline(s) for the conversion project. The last step in the project scope phase is a determination of the authorization and funding of the conversion project. Project cost responsibility, and authorization and payment for the project, will be made pursuant to company-specific policies and procedures, Commission-approved terms and conditions, an existing negotiated contract with a customer not under the jurisdiction of the Commission, or in accordance with an existing franchise agreement.

<u>Phase 2 – Preliminary Layout</u>

The preliminary layout phase begins with an information-gathering step, which consists of an evaluation of the field conditions within the area of the conversion project. The company will either perform, or cause to be performed, a determination of the location and depth of existing utility facilities (including existing underground electric, natural gas, water and sewer lines) and prepare preliminary site plans of the existing utility facilities and the existing field conditions.

The company will also gather information concerning other planned infrastructure improvements scheduled to occur simultaneously with the conversion project or in the near future. Examples of other infrastructure improvements include the widening of streets or alleyways, the construction of new or improvements to existing sidewalks, and the installation of new or upgrades to existing street or area lighting. The company will also begin its preliminary right-of-way research to determine where existing overhead distribution facilities are located. The company may have prior rights to private land, as well as to public right-of-ways. The company may also have rights to construct overhead distribution facilities, but may not have those same rights with respect to underground distribution facilities. The purpose of this early research is to assist the company in the determination of cost responsibility and the allocation of costs.

Once sufficient information has been obtained to allow the company to proceed, a preliminary layout of the line route and the location of surface mounted transformers, switches and other required equipment ("distribution facilities") will be prepared. As part of its preliminary layout, the company will take a number of externalities into consideration. Examples of such externalities include forecasted customer and load growth and the impacts of the conversion project on reliability, aesthetics, and the environment. The environmental assessment could include interaction with any number of stakeholders, such as local, state and federal agencies, including, but not limited to, the Virginia Department of Environmental Quality and/or the U.S. Army Corps of Engineers.

As a final step in the preliminary layout phase of a conversion project, the company will identify the means of installation of the distribution facilities. Consideration is given to trenching size and depth, the use of duct banks, and direct burial of the underground cable.

Once the company has completed the preliminary layout, it is shared with and reviewed with the customer and, as necessary, with other interested stakeholders. Property owners within and adjacent to the conversion area are informed of the company's plans for the conversion project. The company also provides an opportunity for public comment and often makes appearances at public meetings. It is also during this phase that the company will begin negotiations with property owners with respect to required new rights-of-way. As a final step to the preliminary layout phase, the company will distribute the preliminary layout to all stakeholders and work with the stakeholders to complete the layout.

Phase 3 – Detailed Design

Based on the completed preliminary layout, the company will initiate the detailed design phase of the conversion project. The company will determine what materials are required to complete the conversion project and the cost of such materials. The company will finalize the location of the equipment (distribution facilities). The company will perform an analysis of the labor requirements and costs associated with the labor requirements.

During the detailed design phase, the company will, to the extent that they are not already available, begin preparing all necessary right-of-way agreements and prepare final design plans or plats. It is during this phase that the company will deal with any externalities identified in the preliminary layout phase. It is also during this phase of the conversion project that the company will plan for dealing with any anticipated impact on the environment within the project area. Examples of environmental concerns that the company might have to deal with include contaminated ground soil, wet lands, and salt contamination. Detailed reviews of customer and load growth impacts, reliability impacts or other externalities are taken into consideration during the detailed design phase. Finally, all required internal approvals for the design and funding of the conversion project are secured.

After securing all of the required internal approvals, the company will review, with the customer and stakeholders, the detailed design and obtain the necessary authorization for payment. The method and timing of payment(s) varies from project to project.

Phase 4 – Resource Scheduling

During the resource-scheduling phase, the company will identify any working restrictions that may affect the construction timeline for completing the conversion project. Examples of working restrictions include the inability of the company to close streets or lanes during certain hours of the day, such as rush hour, and limitations on construction activities in certain areas or seasons due to tourist activity or special events.

During the resource-scheduling phase, the company will decide on the labor force that will be dedicated to the project. The labor force may be comprised of company employees, construction contractors or a combination of both. It is also during this phase that the company's supply chain or procurement group will begin the advanced ordering of necessary equipment (distribution facilities). If the decision is made to use contractors, the company will begin the process of requesting bids, negotiating terms and conditions and executing required agreements.

As a final step in the resource-scheduling phase, the company will prepare a construction timeline for the customer and review the timeline with the customer.

Phase 5 – Pre-Construction

During the pre-construction phase, the company will obtain all necessary permits. Permits may be required from federal, state and local authorities, as well as other stakeholders such as railroad owners and historical societies. The company will provide notification of the construction timeline to all public utilities that have facilities attached to the existing overhead distribution facilities within the conversion area. Joint use notification is also provided to all public utilities that may be involved in joint trenching.

The company will again provide public notice, the opportunity for public comment and make itself available to the public. The company will work with the stakeholders to coordinate any related infrastructure improvements identified during the preliminary layout phase. The company will obtain all necessary easements, consistent with rights-of-way that were previously agreed to, that are required to begin construction. The company will perform, or cause to be performed, a land survey of the construction area, including the routing and equipment locations. At this stage of the process flow, the company and stakeholders have already devoted considerable time and resources to the planning phases of the conversion project.

Phase 6 – Construction

During the construction phase, the most important issues to be considered are safety (utility and public), regulatory compliance with all permit conditions, and communication with property owners. The company will need to coordinate street and sidewalk closures and traffic control. The company's project coordinator(s) will coordinate the staging of materials and labor activities. The company will perform, or cause to be performed, tree and brush trimming and/or removal, and locate and mark all existing underground utilities.

Once an area has been cleared of vegetation and existing underground utilities have been located and marked, the company will begin trenching, installing transformation and duct banks, and pulling or burying the underground cable. This is followed by backfilling and surface restoration, which varies from project to project and may require restoring streets and sidewalks to local specifications, and sowing grass.

Conversion from overhead to underground also places construction requirements on individual property owners in order for their facilities to accept underground service. Service entrance cables (i.e., the lines from the transformers to the buildings) must be buried, and service entrances and meter bases must be modified to accept underground lines. In most instances, these modifications would require a permit from the locality and an electrical inspection. In addition, where existing aboveground utility poles also served as street lamps, removal of the poles would require placement of new street lights.

Once the placement of the new underground facilities has been completed, they are placed into service. This will, in most cases, result in localized power outages and may involve the installation and removal of temporary services. Only after the new underground facilities have been energized, can the existing overhead distribution facilities be de-energized, dismantled and removed. This begins with the removal of all attachments to the existing overhead poles and culminates with the removal of the overhead facilities and any necessary surface restoration. It is during the construction phase, depending on the project authorization, that the company will begin progressive billing (installments) to the customer for payment, if payment was not made up-front.

Phase 7 – Post-Construction

At the completion of the construction phase, all facility records, as-built drawings, maps and geographic information system ("GIS") data – both utility and public – must be updated and maintained. The total cost of the conversion project is accounted for, the costs are finalized, and the final billing is prepared and presented to the customer for payment.

Additional Discussion

The preceding narrative provided a fundamental description of a major overhead-to-underground distribution conversion project, assuming an open trench with a concrete (duct bank) encased mainline circuit in an urban area. In general, open trenching has been the traditional method to install underground utility distribution systems. However, underground directional boring techniques, designed to replace traditional trenching, represent an emerging technology that possibly has the potential to expedite construction and reduce costs in some applications. A 1999 study for the California Energy Commission[14] suggested that underground horizontal drilling has several advantages over open trenching.[15]

Another potential means to reduce the costs and other impacts of traditional trenching is joint trenching for multiple utilities. Some of the potential advantages of joint trenching include reduced installation, maintenance and repair costs as well as decreased customer inconvenience; however, "co-location also sometimes presents significant technical, safety, contractual and regulatory challenges which, in some cases, can substantially reduce or even negate the net benefits of co-location."[16] The use of the same physical structures by multiple utilities is an accepted practice in overhead distribution; however, it is not widely employed for underground distribution.[17] Typically, electric distribution and telecommunications facilities are placed in separate trenches with separate construction schedules.

The two preceding footnoted references describe pilot projects that have demonstrated the successful implementation, separately, of either horizontal directional drilling or joint trenching, but not both simultaneously. However, one municipally owned electric utility in Oklahoma recently successfully completed, with the help of advanced technologies and drilling techniques, a small electric distribution directional boring project and anticipates that with sufficient notice, telecommunications companies may take advantage of the opportunity to joint-bore in some areas, sharing the cost of bundling two conduits in one directional bore hole.[18] Local governments that exercise close control or oversight over conversion projects might be more effectual in ensuring that potential cost-saving practices, such as directional boring and joint trenching, are considered.

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[14] S. Wirsching (San Diego Gas and Electric), *Trenchless Burial Equipment*. October 1999.
[15] Ibid. More environmentally friendly, fewer outages, improved safety, reduced construction costs, faster installation time, less disruption to consumers. p. 10.
[16] *Putting Cables Underground Working Group Report*, Commonwealth of Australia, Finding 17, 1998.
[17] A. R. McDonald (MasTec North America), "Success in the Trenches," *Transmission & Distribution World*, 1 December 2001, http://tdworld.com/mag/power_success_trenches/index.html, (11/1/2004).
[18] D. Sherrick (Edmond Electric), "Overhead to Underground Conversion in Oklahoma," *T&D World*, 1 August 2004, http://tdworld.com/mag/power_overhead_underground_conversion/ (11/2/04).

IMPACT IDENTIFICATION

The examination of impacts (costs and benefits) is an important feature of any complex policy assessment, such as the undergrounding of distribution facilities. Three distinct tasks have been identified[19] as important to the selection of a manageable set of impacts to examine: listing all possible impacts, structuring them in a coherent manner, and selecting as criteria those impacts which are significant enough to merit actual assessment. The impacts identified for this feasibility study were derived from (1) public input submitted in writing to the Commission Staff and electronically to the Commission web site on HJR 153, (2) responses to the generic questions submitted to interested parties, and (3) a literature search of recent studies on undergrounding. These impacts were then categorized by the Staff as follows:

1. Economic Impacts on Utilities
    - Initial cost
    - O & M cost (including tree-trimming and post-storm restoration)
    - Post "hundred-year" storm rebuild cost
    - Lost sales to utilities
    - Competitive neutrality

2. Environmental Impacts
    - Aesthetics (removal of aerial facilities, back lot to front street relocation)
    - Tree health (limbs/roots)
    - Open trenching

3. Health and Safety Impacts
    - Motor vehicle accidents (fatalities and injuries)
    - Public accessibility/electrical hazards (downed lines, pad mounted equipment vandalism)
    - Industrial hazards (electrocutions from crane and mast contacts, falls, work zone vehicle accidents)
    - Underground damage prevention

4. Socioeconomic Impacts
    - Motor vehicle accidents (comprehensive costs)
    - Shift in preference between landline and wireless communications
    - Costs associated with subsequent installation of advanced cable services
    - Reliability during severe weather conditions
    - Reliability during normal weather conditions
    - Homeowner/utility relations regarding tree trimming
    - Economic development opportunities for local governments
    - Property values

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[19] Armstrong, J.E. and W.W. Harmon. *Strategies for Conducting Technology Assessment*. Report to the Division of Applied Science and Research Applications, National Science Foundation, Washington, DC. Stanford University, December 1977, p.45.

- Pedestrian impacts (sidewalks and other walkways)
- Disruptions due to initial construction
- Impact on developable area
- Impact on streetlights
- Rewiring of service entrance equipment
- Disruptions for maintenance
- Right-of-way/easement width
- Availability of linemen to perform new connections

5. Technical Impacts
    - Life expectancy of equipment
    - Delivery line losses
    - Electric and telecommunications interaction/interference
    - Susceptibility to dig-ins
    - Flexibility relative to upgrading and reconfiguring circuits
    - Utility failure analysis
    - Outage repair time
    - Geographic scale of outages
    - Susceptibility to flooding

6. Regulatory/Legislative/Judicial Impacts
    - Right-of-way agreements
    - Authority of localities to require undergrounding
    - Recovery of undepreciated aerial assets/stranded assets
    - Rate cap policy
    - Tax effect recovery factor policy

For the purpose of condensing the long list of identified impacts to a manageable number to analyze in more depth, the Commission Staff requested the attendees of the August 16, 2004, kickoff meeting to rank the most important criteria for determining whether the placement of distribution facilities underground is desirable and in the public interest. The attendees chose "cost" as the most important criteria. In this case, "cost" was defined as the impact of net life cycle cost on utilities (and ultimately individual consumers), where net costs factor in initial construction costs, annual operating and maintenance ("O&M") costs, and annual savings anticipated from a reduction in the costs associated with tree-trimming, post-storm restoration, motor vehicle damage to utility facilities, and lost revenues from unmet demand.

The kickoff meeting attendees chose "reliability" as the next most important category for determining whether undergrounding is desirable and in the public interest. Reliability has implications relative to direct costs (post-storm restoration and lost revenues from unmet demand mentioned in the previous paragraph), as well as implications relative to consumer annoyance and indirect costs on the economy. Day-to-day reliability and reliability during catastrophic storms were deemed to be about equally important among the group as a whole. Other feasibility issues that were ranked important by a significant number of the attendees included impacts related to health and safety (including vehicular accidents with utility poles), aesthetics, increased costs due to taxation of contributions in aid of construction ("CIAC"), underground damage prevention, right-of-way acquisition, operational impacts, and the authority of municipalities relative to the implementation of local undergrounding policies.

The most significant impacts and feasibility issues are analyzed in the upcoming five major sections: *Utility Cost/Benefit Analysis*, *Ocean View Case Study*, *Analysis of Benefits to the Economy from Undergrounding*, *Summary Review of Economic Costs and Benefits*, and *Discussion of Additional Impacts and Feasibility Issues*. The first of these five major sections, *Utility Cost/Benefit Analysis*, addresses not only the costs but also the savings that utilities could realize as a result of placing distribution facilities underground. In particular, the utility cost/benefit analysis will address initial construction costs, the economic impact on customers, annual O&M costs, benefits (avoided costs) associated with the minimization of rebuild and restoration efforts following catastrophic storms, and increased revenues from sales due to an expected reduction in power outages.

UTILITY COST/BENEFIT ANALYSIS

Net Life Cycle Costs to Utilities

The initial construction costs associated with the placement of distribution facilities underground are substantial. Some operating and maintenance costs associated with underground facilities can be high, as well. However, the placement of distribution facilities underground also results in some savings for the utilities. These savings are due, in large part, to anticipated reductions in tree-trimming and post-storm restoration costs and, to a lesser degree, reductions in damages to utility facilities due to vehicular accidents. Finally, any improvements in reliability from placing facilities underground would result in increased electricity sales and, therefore, additional revenues. These economic cost-benefit issues are analyzed in the following paragraphs for the electric utility companies. The direct costs for the telecommunications/CATV providers are discussed at the end of this section.

Costs of Undergrounding Electric Distribution Facilities

The placement of new distribution facilities underground is generally more costly than new overhead construction. Based on estimates provided by the investor-owned electric utilities and electric cooperatives, the average cost per mile for new electric overhead construction can range from a low of approximately \$15,000 per mile for single phase taps in rural communities to a high of \$250,000 per mile for three-phase lines. The average cost per mile for new underground electric construction can range from \$25,000 to \$1.5 million.

The cost to convert existing overhead facilities to underground, which involves the installation of new cable in existing developments and the removal of old overhead wire, equipment and wooden utility poles, can be very costly.[20] Based on estimates provided by the investor-owned electric utilities, the average cost per mile to convert overhead electric distribution facilities to underground can range from a low of approximately $150,000 per mile for single-phase cable in rural communities[21] to a high of approximately $3 million per mile for three-phase cable in heavily commercial urban areas.[22] The mileage cost associated with any conversion project involving a specific circuit could be higher or lower depending on the particular circumstances of the proposed project. The estimated costs to convert an individual customer's service drop (from the pole to the residence) to an underground service lateral ranged from approximately $1,000 to $7,000.

The Staff did not receive conversion cost estimates from all of the electric cooperatives in the state; however, an estimate provided by one of the state's largest electric cooperatives indicated average mileage costs in rural areas ranging from approximately $100,000 per mile for single-phase cable to approximately $500,000 per mile for three-phase bulk feeder cable. Another estimate received from one of the smaller electric cooperatives indicated average mileage costs in rural and suburban areas ranging from $40,000 per mile for single-phase cable to $175,000 per mile for three-phase feeder cable. Although the estimated mileage costs of conversion in rural areas served by electric cooperatives are less than elsewhere, the cost per customer would be substantial because customer density is less in those same areas.

Using the estimates provided by the electric utilities, the cost to convert all existing overhead electric distribution facilities in the state to underground would probably cost over $80 billion.[23] The totals for each utility that provided estimates are provided in the following tables. The bases of the estimates for Virginia Power and APCO are provided in Appendix D. The cost estimates typically include primarily (1) materials associated with new underground facilities (net of salvage value of existing overhead facilities), (2) labor associated with removal of the existing overhead facilities and installation of the new underground facilities (mostly trenching/boring), (3) planning, design and engineering, (4) general, administrative, construction, and material overheads, (5) contingencies, and (6) acquisition of easements.

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[20] The average cost per mile to install underground distribution facilities in a new development or green field area is less than the cost per mile for converting overhead facilities to underground but still significantly greater than the average cost per mile for new overhead distribution facilities.

[21] APCO and Old Dominion Power Company service territories.

[22] Three-phase bulk feeders and three-phase taps in Virginia Power's service territory.

[23] Only two of the electric cooperatives provided total conversion cost estimates, but based on their average unit conversion cost of approximately $200,000 per mile, it would cost approximately $6.8 billion to bury the cooperatives 34,000 miles of overhead lines. Assuming 90 percent of the cooperatives' 411,000 customers have overhead service and a conversion cost of $4,000 per service, it would cost an additional $1.5 billion to convert all of the cooperatives' overhead service drops to underground.

Investor Owned Utilities	All Feeders and Taps ($ billions)	Residential Services ($ billions)
Appalachian Power	10.237	2.539
Delmarva Power	0.068	0.067
Virginia Power	52.462	6.778
Old Dominion Power	0.400	0.027
Potomac Edison	2.434	0.073

Electric Cooperatives (only two provided estimates)	All Feeders and Taps ($ billions)	Residential Services ($ billions)
Rappahannock Electric (rural district only)	1.011	0.002
Prince George Electric	0.149	0.049

The Staff notes that these cost estimates are based on various simplifying assumptions, have not been derived from detailed engineering studies, and, therefore, contain significant uncertainties and inconsistencies. Contingencies may have been added by the companies to address these uncertainties. Some utilities reported specific factors that were not included in the estimates, which could result in additional costs.[24] In addition, if general and administrative costs – some of which might not be incremental costs – were to be eliminated, the estimates would be significantly less. Additional cost reductions might be possible if economies of scope and scale were considered. On the other hand, actual costs could increase as a result of possible price escalation due to an anticipated excess demand on resources during a comprehensive statewide initiative.

Economic Impact of Undergrounding on Electric Utility Customers

"Overnight" Direct Costs. As indicated in the previous subsection, the "overnight" direct cost of converting currently existing overhead electric utility distribution systems to underground is estimated to be approximately $80 billion. This equates to approximately $800,000 per mile to underground the investor-owned utilities' and cooperatives' nearly 100,000 miles of overhead distribution lines. Divided among the investor-owned utilities' and cooperatives' 3.1 million customers, the average cost per customer would be approximately $27,000.

[24] APCO reported that its direct cost estimates did not include general & administrative and construction overhead costs or underground feeder sectionalizing or voltage correction costs, which would substantially increase costs. For purposes of the above table, the Staff added in overhead costs for consistency with the other reporting investor owned utilities. Rappahannock Electric reported that its estimates did not consider the impact of future conductor capacity for a long-range work plan load growth. Prince George Electric noted that total conversion would incur the additional costs of replacing every pole mount transformer with a more expensive pad mount transformer.

Impact on Customer's Electric Utility Bills. Assuming a total investment by electric utilities of $80 billion to relocate currently existing overhead distribution lines to underground, the annual levelized revenue requirement on a per customer basis would be approximately $3,000 per year over the life of the facilities. This result is based on a levelized annual carrying cost factor of 13 percent. Different assumptions regarding finance costs or useful life of the facilities could result in different carrying cost factors and revenue requirements. Any impact on individual customers would depend on the rate design methodology. The following table provides a summary of the assumptions and annualized revenue requirements.

Total Investment $80 billion	**Annual Carrying Cost Factor 0.13**
Annual Revenue Requirement	$10,400,000,000
Total Number of Customers	3,137,023
Total Annual MWH Sales	99,926,726
Annual Revenue Per Customer	$3,315

In addition to the impact to utility bills, individual customers would also be responsible for any costs necessary to ensure their service entrance equipment is compatible with underground service.

Additional Impact of Life Expectancy. A comparison of the life expectancy between overhead and underground systems is an important consideration in calculating the impact of the direct costs on consumers. If the life expectancy of underground distribution systems is shorter than that of overhead systems, underground facilities would have to be replaced more frequently than overhead facilities. The need to replace equipment more often with an underground system would increase the overall cost of an underground system relative to an overhead system.

According to a 2003 report by the North Carolina Public Staff on the feasibility of placing electric distribution facilities underground ("North Carolina Feasibility Study"), the life expectancy of underground cable installed today is thought to be greater than 30 years, while an overhead system has a life expectancy of more than 50 years.[25] Likewise, a 2003 task force report to the Maryland General Assembly ("Maryland Task Force Report") indicated that overhead distribution lines have a longer life than underground cable.[26] In response to a data request from the Commission Staff, some of Virginia's electric utilities provided estimates as high as 40 years for the anticipated life expectancy of new underground cable and as high as 60 years for new overhead systems.

[25] *The Feasibility of Placing Electric Distribution Facilities Underground*, Report of the Public Staff to the North Carolina Natural Disaster Preparedness Task Force ("North Carolina Feasibility Study"), November 2003, p.18.
[26] Task Force to Study Moving Overhead Utility Lines Underground, Maryland, December 2003, p. 55.

In spite of the above general estimates, any evaluation of the anticipated life expectancy of a new underground distribution system against an existing or new overhead distribution system for a specific project should consider the type of underground system to be installed and the location of the project. Proposed undergrounding projects should be evaluated individually as part of a cost-benefit analysis to determine the impact of life expectancy on the feasibility of the project.

Other studies' estimated cost impacts. In the North Carolina Feasibility Study, the North Carolina Public Staff estimated that conversion of overhead electric distribution lines to underground would have a rate impact of approximately 10 cents per kWh, which would increase residential rates by 128.7 percent, commercial rates by 162.6 percent, and industrial rates by 216 percent.[27] The North Carolina Public Staff noted that in addition to these estimates, there would be additional costs to bury telecommunications facilities and costs to individual customers in order to convert their facilities to accept underground service.

According to a report by Exeter Associates, Inc., which is included in the Maryland Task Force Report, assuming an average cost per mile of $450,000 for undergrounding the existing overhead distribution systems of Potomac Electric Power Company ("PEPCO") and Baltimore Gas and Electric Company ("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 were estimated to be approximately 36 percent for BGE customers, and 46 percent for PEPCO customers.[28]

An Australian Underground Working Group estimated the total cost of a comprehensive program to put existing overhead electricity and telecommunications cables underground to be $23.7 billion for 4.2 million households in urban and suburban Australia, an average of $5,516 (AUD) per household.[29] These figures reflect a range of costs covering different terrain and installation techniques from around the country, and include an averaged component for putting aerial public switched telephony and broadband cables underground. However, the Working Group notes that accurate costs can only be obtained from a comprehensive underground network engineering design, material listing and labor analysis.

Annual O&M Costs[30]

Proponents of placing distribution facilities underground often anticipate potential savings in operating and maintenance ("O&M") costs for underground facilities relative to O&M costs for overhead facilities, particularly with respect to tree trimming and restoration of service after major storms. These O&M costs consist of maintenance and repair (including costs associated with vehicular accidents), preventive maintenance

[27] North Carolina Feasibility Study, p. 28.
[28] *Undergrounding Electric Utility Lines in Maryland*, prepared by Exeter Associates, Inc. for the Maryland Energy Administration and the Power Plant Research Program, December 30, 1999.
[29] *Putting Cables Underground Working Group Report*, Executive Summary and Key Finding, AUS.
[30] In this context, O&M costs include restoration costs that may be expensed or replacement costs that are capitalized.

(including tree trimming), and service restoration (including restoration costs relative to major storms – but, for the purpose of this subsection, excluding catastrophic storms such as Hurricane Isabel, which are addressed in the following subsection). Although tree-trimming, post-storm restoration and vehicular-accident related O&M costs can be nearly eliminated by placing overhead facilities underground, non-trimming/non-accident O&M costs could increase since such costs are often higher for underground facilities than for overhead facilities.

In order to compare annual O&M costs associated with overhead and underground distribution facilities, the utilities were asked to provide their 2003 O&M costs on a mileage basis. Delmarva Power and the four electric cooperatives that provided estimates reported O&M costs for underground distribution facilities that were approximately one-third of the costs for overhead facilities, on average. APCo and Potomac Edison reported that O&M costs for underground facilities were roughly one-half to two-thirds, respectively, of O&M costs for overhead distribution facilities. Overhead and underground O&M costs for Virginia Power were essentially equal.[31] For Old Dominion Power Company, the O&M costs for underground distribution facilities were significantly higher than for overhead facilities because ODP installs all of its underground primary and secondary cable by means of direct buried conduit or concrete encased duct banks.

In general, the Staff believes that the impact on overall O&M costs[32] of placing overhead distribution facilities underground would not be significant on a statewide basis. In other words, placing all currently existing overhead facilities underground probably would not result in a significant reduction in O&M costs. This is consistent with the conclusion of the North Carolina Feasibility Study that O&M mileage costs for an overhead system and a direct-buried underground system are comparable.[33] An Australian Underground Working Group estimated that the quantifiable benefits from reduced tree trimming and repairs and maintenance represent only around four percent of the total cost of converting overhead lines to underground.[34] If it were assumed that total O&M costs could be reduced – via undergrounding – by the full cost of tree trimming, the savings to the utilities would be approximately $50 million per year.

Within any particular utility system, the impact on O&M costs of placing overhead facilities underground would probably depend on the type of underground system installed and the extent of overhead tree trimming that could be eliminated. For example, converting a specific overhead distribution circuit that has little tree exposure (and therefore requires little or no periodic tree trimming) to an underground duct bank

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[31] Based on Staff's assumption that 100% of vegetation management and storm restoration costs are attributable to overhead facilities, DVP's OH and UG O&M costs were approximately $1800 per mile.
[32] Including maintenance, repair, tree-trimming, vehicular accidents, and post-storm restoration in total.
[33] North Carolina Feasibility Study. [The report also noted that the annual average O&M mileage cost for an urban underground system that requires installation in duct bank is more than four times that of an overhead system.] p. 25.
[34] *Putting Cables Underground Working Group Report*, Commonwealth of Australia, Ch 2, Table 12, 1998.

would probably result in an increase in annual O&M costs.[35] In other cases, conversion of overhead facilities to underground could result in a significant reduction in O&M costs. A detailed analysis of the anticipated impacts on annual O&M costs should be performed as part of any cost-benefit analysis for specific overhead distribution circuits being considered for underground conversion.

Elimination of "Hundred-Year" Storm O&M Costs

There is little doubt that placing distribution facilities underground essentially eliminates the lengthy outages and substantial rebuild and restoration costs associated with "hundred-year" hurricanes and ice storms. The difficulty is determining how often such storms would impact the various utility systems over the lifetime of the underground facilities. A summary of the restoration costs associated with Hurricane Isabel in 2003 is provided in the following table.

Hurricane Isabel / **Utility**	Restoration Cost ($ millions)
Appalachian Power	2.6
Delmarva Power	0.609
Old Dominion Power	0
Potomac Edison	3.3
Virginia Power	194.5
Electric Cooperatives	16.5

Based on the above estimates provided by the utilities, it is apparent that Hurricane Isabel resulted in restoration costs greater than $200 million before tax write-offs and mitigation payments received from the Federal Emergency Management Agency; however, not all utilities were affected equally. Had Hurricane Isabel affected the other utilities to the same extent that it affected Virginia Power, restoration costs conceivably might have approached $600 million.[36] Assuming that no more than the equivalent of two such storms (one "hundred-year hurricane and one "hundred-year" winter storm) would devastate each utility's entire system over the lifetime of the underground facilities, then placing all overhead facilities in the state underground could potentially avoid as much as $1.2 billion over the lifetime of the system, or $40 million per year (in current dollars) assuming a 30-year life expectancy of the new system.

Reduction in Day-to-Day Lost Electricity Sales

Utilities lose millions of dollars in revenues annually as a result of power outages from overhead distribution facilities. Based on reliability statistics reported by electric

[35] O&M costs for urban underground duct bank systems are high because duct-bank related equipment is more expensive to repair, inspection requirements are more rigorous, and they typically include 3-phase cable and a higher density of equipment per mile in order to meet the concentrated load requirements.

[36] Based on Virginia Power's damage estimate (converted to an average per line mile estimate) applied equivalently to all distribution line miles in the state. The foregoing assumes that all of the restoration costs associated with Hurricane Isabel were attributable to damages incurred on overhead facilities.

utilities nationwide, the national average service availability index[37] was 99.8 percent for the five-year period 1998-2002.[38] Thus, nationwide, utilities are losing approximately two-tenths of a percent in revenues as a result of unmet demand. Approximately 86 percent of all outage hours nationwide can be attributed to the distribution system; however, not all of these could be eliminated by undergrounding because some are due to outages from existing underground distribution cable and equipment failures and dig-ins. Nevertheless, a significant portion of lost revenues could be eliminated as a result of converting overhead distribution facilities to underground. For purposes of the calculation in this subsection, it is assumed that 80 percent of all outage hours could be eliminated by placing the remaining overhead distribution facilities underground.[39] Given that the state's utilities sell approximately 100 million MWH annually at an average rate of 6.3 cents per kWh, the Staff estimates that utilities in Virginia could recover at most an additional $12 million per year (before taxes) via eliminated lost sales by converting the state's overhead distribution facilities to underground.[40]

Elimination of Lost Electricity Sales from "Hundred-Year" Storms

The placement of overhead distribution facilities to underground would also essentially eliminate the lost electricity sales as a result of "hundred-year" hurricanes and ice storms. The state's utilities were asked to provide their estimates for lost electricity sales and revenues as a result of Hurricane Isabel. The results are provided in the following table.

	Estimated Sales Lost (MWH)	**Estimated Revenues Lost ($)**
Appalachian Power	3,852	169,600
Delmarva Power	0.46	46
Old Dominion Power	0	0
Potomac Edison	3,800	90,000
Virginia Power	405,000	18,300,000
6 Electric Cooperatives	30,299	2,440,700
TOTAL	442,951	21,000,346

[37] The average service availability index is a measure of the percentage of the customer hours of service demand that was actually served by the utilities.
[38] EEI, *2002 Reliability Report*, November 2003.
[39] In 2002, approximately 79 percent of the total customer hours of outages were attributable to interruptions on overhead distribution facilities on Dominion Virginia Power's system. The remaining 21 percent were attributable to interruptions related to bulk power, failure of underground facilities, dig-ins, and company-initiated activities. Distribution facilities placed underground would still be subject to outages from dig-ins and failure of underground equipment.
[40] 100 million MWH sales x (1 - .998) x $63 per MWH x 0.8, where 0.8 = the estimated fraction of total outage hours attributed to the existing overhead distribution system. The benefit estimated is overstated for several reasons: (1) the price of electricity used in this example includes variable costs, such as fuel cost, (2) utilities in the state generally have achieved an average service availability index that is higher than the national average, and (3) new underground facilities would still be vulnerable to equipment failures and dig-ins, so that it is more likely that only 60% of outage hours could be avoided.

Based on the above estimates provided by the utilities, it is apparent that Hurricane Isabel resulted in lost revenues greater than $20 million (before taxes); however, not all utilities were affected equally. Had Hurricane Isabel affected the other utilities to the same extent that it affected Virginia Power, lost revenues conceivably might have approached $26 million statewide.[41] Assuming that no more than the equivalent of two such storms (one "hundred-year hurricane and one "hundred-year" winter storm) would devastate each utility's entire system over the lifetime of the underground facilities, then placing all overhead facilities in the state underground could avoid as much as $52 million in lost revenues over the lifetime of the system, or approximately $2 million per year (in current dollars) assuming a 30-year life expectancy of the new underground system.

The above-estimated lost revenues associated with outages from both day-to-day occurrences and "hundred-year" storms appear significant; however, the Staff recognizes that revenues not collected by utilities remain in the pockets of the consumers as a result of lower electric bills. Consumers have the opportunity to spend their retained earnings on other goods and services, but probably would rather have had their electricity. In addition because utility revenues are taxed, utilities would not receive the full benefit of the revenues had they been collected; however, the taxes would have benefited the government and ultimately the citizens. Assigning these "transfers of wealth" as potential costs or benefits of undergrounding introduces uncertainties; however, such transfers of wealth could have implications with respect to funding the costs associated with converting overhead distribution facilities to underground.

Direct Costs to Telecommunications/CATV Providers

The "overnight" direct cost of converting currently existing overhead telecommunications systems to underground was estimated by the telecommunications providers to be approximately $10.6 billion. This equates to approximately $230,000 per mile to underground the companies' nearly 46,000 miles of overhead lines. Divided among the telecommunications companies' 4.5 million customers, the average cost per customer would be approximately $2,400. The Staff did not calculate the levelized annual cost to telecommunications customers.

In the case of telecommunications and CATV systems, the switching centers or head ends were not considered as part of the undergrounding study. The main feeder cables, distribution cables, and service wires are all capable of being provisioned underground. The estimated costs for converting the aerial service wires to underground

[41] Based on Virginia Power's estimated percent of annual sales lost (0.57%) applied equivalently to all MWH sold in the state. The foregoing assumes that all of the lost revenues associated with Hurricane Isabel were attributable to damages incurred on overhead distribution facilities, which inflates the actual lost revenues that could be avoided by placing all overhead distribution facilities underground (since some of the losses were a result of impacts to the existing transmission facilities and underground distribution facilities).

were not included in the costs for this study. This aspect of telecommunications and CATV main transmission or feeder facilities is somewhat different than power provisioning in that the main electric transmission lines are not considered for undergrounding in this study due to the extremely high cost.

Cavalier Telecom, Cox Communications, Comcast Phone of Virginia, Sprint/Centel, Sprint/United, Verizon South, and Verizon Virginia were asked by Staff to provide data to assist with the preparation of this study. These companies and their facilities represent 96.9 percent of the access lines in Virginia. Comcast did not respond. Most of the responding companies deemed numbers of subscribers, sheath miles of cable, and the costs associated with undergrounding of their facilities proprietary but consented to release the information only as part of the combined industry data. Cox Communications, Verizon Virginia and Virginia Power participated in the Ocean View undergrounding study. Within the reporting companies there are approximately 46,000 sheath miles of aerial cables. (This number does not reflect aerial service wire footages.) During 2003 and 2004 Verizon constructed 80.8 percent of its new facilities as underground and removed 81 sheath miles of aerial cable. Sprint, since 2000, constructed 63 percent of its new cable facilities underground. Although facilities are still being constructed aerially, the general trend in telecommunications has increasingly been to underground both feeder and distribution systems.

<u>Summary of Utility Cost/Benefit Analysis</u>

This section, *Utility Cost/Benefit Analysis*, addressed the primary economic costs and benefits to the utilities that could result from an undergrounding initiative. The total "overnight" costs of relocating the currently existing overhead distribution lines to underground were estimated to be approximately $75 billion for the investor-owned electric utilities, $8 billion for the electric cooperatives, and $11 billion for the telecommunications providers. The resultant levelized annual revenue requirements for the electric utilities alone would be approximately $10 billion per year. On the other hand, the estimated annual savings to the utilities as a result of reductions in lost sales and tree trimming and restoration costs is only about $500 million per year. The annual levelized revenue requirement on a per customer basis would be approximately $3,000 per year.

The next section, *Ocean View Case Study*, provides a summary of the estimated cost to relocate a specific circuit in the Ocean View area of Norfolk. Following that, an analysis of the potential benefits to the overall economy is provided in the section titled *Analysis of Benefits to the Economy from Undergrounding*.

OCEAN VIEW CASE STUDY

Background

The Ocean View area of Norfolk is a community situated alongside the southernmost part of the Chesapeake Bay. The Staff chose this area to study the feasibility of undergrounding the existing aerial utility facilities for several reasons. First, Ocean View represents a mix of commercial and residential development. Second, parts of the area are currently undergoing significant renewal and redevelopment activities of which the utilities participating in the case study (Verizon, DVP, and Cox) are well familiar. Third, Ocean View was in the path of Hurricane Isabel and, therefore, was heavily affected by the storm and its aftermath. Finally, the aerial facilities currently in use in much of the area are particularly representative of the "visual pollution" referenced in HJR 153.

Scope and Assumptions

On Friday, October 15, 2004, members of the Commission's Divisions of Energy and Communications, along with representatives of Verizon, DVP, and Cox, toured Ocean View in an effort to establish the scope of the study. From that outing, and in consultation with the patron's (Delegate Drake) office, it was determined that the Ocean View undergrounding feasibility study would encompass the seven-mile stretch of Ocean View Avenue (US Route 60), and immediate vicinity, as measured from the Norfolk side of the Hampton Roads Bridge Tunnel to the Norfolk/Virginia Beach line.

During the tour, the utility engineers first noted that much of the original roadway was widened from two to four lanes, which has the effect of severely limiting the amount of physical area available for replacing aerial facilities with buried or underground facilities. The engineers also noted that, while the poles and wires disappear when underground, the equipment (transformers, terminals, repeaters, etc.) on the poles (euphemistically known to many as the "big green boxes") will need to be placed above ground and, in most cases, in public view.

DVP and Verizon own the utility poles in the case study area. Cox does not own poles, but attaches its overhead CATV facilities (and those associated with its competitive telecommunications services) to either DVP's or Verizon's poles via pole attachment agreements.[42] (The cost and work time estimates discussed later assume that the City of Norfolk will secure any easements or rights-of-way necessary from property owners prior to the commencement of the undergrounding effort.)

It is also assumed that electric, telecommunications, and CATV underground facilities would be constructed separately. This assumption is based on the prevalence of sidewalks, parking lots, and driveways. In a concrete or asphalt terrain, such as Ocean View, the telecommunications utilities agreed that the most efficient and least destructive

[42] For the purpose of the Ocean View study, we considered as representative only the facilities of Verizon, DVP, and Cox, although a few other telecommunications companies also attach to DVP and Verizon poles.

approach to undergrounding is to bore under these hard surface obstructions. The existing overhead facilities would remain in use until the undergrounding project was completed.[43] The following is a summary of Verizon's anticipated scope of work:

Verizon's aerial plant is extensive and is positioned on both Verizon and DVP poles. There are 108 Verizon poles and 206 DVP poles that carry Verizon-owned aerial plant along Ocean View Avenue. Various cable sizes exist in the case study area, ranging in size from 50 pairs to 1800 pairs. In developing its cost estimate, Verizon assumed the placement of buried cables equal in size to the corresponding aerial plant. This conversion will not result in increased capacities or enhanced cable routing for Verizon.

Cables of various sizes from 50 pair to 1800 pair will be buried for a total of 46,854 feet. Due to limited easements, road crossings, driveways, etc., cable placement was calculated assuming directional boring. Splicing operations will be required at 395 locations along the route. Approximately 1200 service drops will be converted from aerial to underground. Aerial removals will involve some 42,851 feet of cable.

Virginia Power determined that a duct bank would be necessary to place electric facilities underground on Ocean View Avenue to allow repair and replacement of cables. Service restoration times and maintenance costs would be unacceptable if electric facilities were direct buried under asphalt or concrete and extensive landscaping.

Joint construction was not assumed in developing Verizon's cost study. If undergrounding becomes a reality, joint construction will be considered by the parties involved. Given the unpredictability of rights-of-way acquisition, such costs are not included in the estimate provided above. The City of Norfolk should procure any required rights-of-way for use by the utilities.

Cost and Time

Except in extreme cases, such as rocky terrain, the placement of aerial utility facilities underground is generally feasible. This axiom certainly holds true for Ocean View as well. The issues, then, when it comes to undergrounding projects, usually come down to those of practicality and cost.

The overall cost for the Ocean View undergrounding project was estimated by the utilities to be approximately $54 million, of which the vast majority is associated with the cost estimate of DVP. The project is estimated to take from two to five years to complete. According to DVP, the high cost is due to the limited space to install facilities and the density of services. DVP's cost estimate is based on placing the main circuit in the street at a depth of greater than 4 feet due to conflicts with public infrastructure and other utilities. The extra depth requires additional costs for excavation, shoring, select backfill, compaction and water removal. Surface restoration costs are high to replace

[43] Generally, existing overhead facilities are not reusable underground.

sidewalks, curbs and road surface. Secondary conduits, conductors and splice boxes are required on both sides of the road because of the density of services.

Practicality

The participants were asked the following question regarding the pros and cons of a project such as the one studied in Ocean View:

What would be the advantages and disadvantages of undergrounding facilities in the Ocean View area? What problems would you likely eliminate and what problems would you likely create?

Verizon Response

Advantages are limited to the aesthetic appeal of buried plant as compared to aerial plant, and certainly the benefit of new facilities on Ocean View Avenue proper. Disadvantages include the potential for service outages during the transition from aerial to underground. Additionally, areas of Ocean View Avenue are prone to flooding, offering the potential for ongoing service problems if buried plant is installed in those areas. The Hurricane Isabel experience showed that buried plant along Ocean View Avenue was more prone to storm damage than was aerial plant.

A significant challenge will be finding the space to place buried plant in the limited rights-of-way and public easements in the study area. It is likely that private rights-of-way will be necessary for substantial portions of the buried placement. These are likely to be expensive and time consuming to acquire. It would make sense for the City of Norfolk to acquire them for all utilities as VDOT does for its highway relocation work.

Cox Response

Underground facilities are more secure during a hurricane. On the other hand, underground facilities get damaged more often by digging.

DVP Response

The primary advantage to placing existing overhead distribution facilities underground along Ocean View Avenue is to address aesthetic considerations through the elimination of the poles and wires along this street. Poles and wires would still be visible one block south of Ocean View Avenue, due to the limited area of this study. Another advantage is that underground systems typically experience a lower frequency of problems because of reduced exposure to weather and tree-related incidents. Removal of the overhead facilities along Ocean View Avenue would eliminate outages caused by vehicle damage to poles. However, switches, transformers, and any other underground equipment having an above-ground profile would still be vulnerable to vehicle damage, especially since the replacement facilities would be installed on city rights-of-way at the edge of the road. Due to the extent of existing development in this area, tree trimming costs are already minimal and little savings would be realized by placing facilities underground.

Disadvantages to undergrounding the overhead facilities along Ocean View Avenue include the large initial capital expenditure, length of time required to implement the overhead to underground conversion, and inconvenience to residents who live in the vicinity of Ocean View Avenue during construction.

Problems that would be created as a result of undergrounding include increased time required to restore service when outages occur, increased maintenance cost, and increased cost to rearrange facilities in the future. Manholes installed as part of the underground facilities can be expected to remain filled with water throughout the year as a result of the high water table in this area. Any maintenance, repair, restoration activity requiring access to these facilities will likely require pumping out the manhole as a first step before failure points can be located. Any future rearrangement of underground distribution facilities required to connect new customers, accommodate road work, or resulting from redevelopment presently occurring along some parts of Ocean View Avenue will be more costly than equivalent work on the existing overhead facilities.

<u>Hurricane Isabel</u>

One of the stimuli for HJR 153 was the hardship caused by Hurricane Isabel. To better gauge the effect of Isabel on overhead utility facilities, the participants were asked the following question:

During Hurricane Isabel, did the aerial plant or buried plant sustain the most damage in the Ocean View area?

<u>Verizon Response</u>

Verizon did not track Hurricane Isabel repair activity by type of plant, but the vast majority of repair activity resulting from Isabel was either due to tree damage or flooding. Given the absence of large trees along Ocean View Avenue proper, the aerial plant experienced minimal damage. The buried plant, especially in the Willoughby area, sustained significant damage from flooding.

<u>DVP Response</u>

DVP tracked the overall number of outages that were experienced during Hurricane Isabel as well as the duration of these outages. However, overhead/underground equipment failures for Hurricane Isabel are indistinguishable. Unlike typical events that are tracked to the individual project type, during larger events, DVP implements an event number to capture overall event activity and minimize the administrative aspects of managing a large imported restoration workforce. As such, DVP did not capture information relative to overhead versus underground problems.

Cost Recovery

The costs for relocating existing overhead facilities are generally borne by the individual property owner, developer, or municipality requesting the service. In the case of municipal projects, as would be the case in Ocean View, it is presumed by the industry participants that the City would be responsible for the project's costs. It should be noted that Verizon Virginia has a tariff on file with the Commission that allows for cost recovery for municipal projects on a pro rata basis from the customers within that political subdivision. Presumably, this pro rata charge would come in the form of a special tax or fee assessed on telephone bills. It should also be noted that, according to Verizon, this tariff has never been utilized. Instead, on large scale projects, requesting localities or developers have paid for the facility relocation work.

Verizon goes on to caution that any cost recovery scheme should be competitively neutral. For example, if Verizon's Norfolk customers were assessed a surcharge and its competitors, such as Cox, Cavalier, and wireless providers were not, then Verizon would be placed in a competitive disadvantage. The Staff would only note that the ever increasing fees, surcharges, and taxes collected from telephone bills represents one of the fastest growing areas of Commission complaints.

Under the assumption that the estimated cost of $54 million to complete the Ocean View Avenue undergrounding project was recovered equally from all of the citizens of Norfolk, the amount per household and business would be $540.00.[44] Obviously, the cost per household or business would be considerably more if it was assessed against only those receiving the direct benefit of the project.

Summary

The Ocean View case study reveals that the primary advantage of undergrounding existing aerial facilities comes primarily from improved aesthetics. Weather related events, even one as devastating as Hurricane Isabel, do not constitute a mandate, at least from the perspective of the industry, to alter its aerial-first approach. Moreover, underground facilities in areas such as Ocean View are more prone to flood damage than wind damage. In the final analysis, as was suggested earlier, the most difficult issues are those associated with cost, cost recovery, and competitive neutrality, the latter of which will be discussed in more detail later in this report. The next section provides an analysis of the potential benefits to the economy that could follow a comprehensive statewide undergrounding initiative.

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[44] For illustrative purposes, the Staff used 100,000 as the number of households and businesses located within the City of Norfolk (94,416 residences, 5,604 businesses). This number was derived from the U.S. Census Bureau, County Business Patterns, as revised December 7, 2004.

ANALYSIS OF BENEFITS TO THE ECONOMY FROM UNDERGROUNDING

Introduction

Many of the economic losses that are associated with overhead utility distribution lines could be eliminated by placing the lines underground. This section provides discussions of the primary potential benefits to the economy that might result if the currently existing overhead distribution facilities were to be placed underground. The categories that will be addressed include avoided costs associated with reduced electric power outages on a day-to-day basis, avoided costs associated with electric power outages from "hundred-year" storms,[45] and avoided costs associated with reduced vehicular accidents with electric and telephone utility poles.

Day-to-Day Impact of Electric Power Outages on the Economy

Numerous studies of existing overhead and underground distribution systems demonstrate that underground systems worldwide are more reliable than overhead systems during both normal and severe weather conditions.[46] According to the North Carolina Feasibility Study – during a recent five-year period – underground distribution systems in North Carolina experienced only half the number of interruptions per mile as overhead systems during normal weather conditions; however, the study also determined that a typical underground outage takes longer to repair and might involve digging up a front yard, sidewalk, or street.[47] Nevertheless, because there would be substantially fewer outages, the average annual outage time experienced by consumers should diminish if overhead distribution facilities are placed underground.

Underground utility distribution systems are also naturally resistant to damage during severe weather. Although underground distribution systems are not invulnerable, such systems essentially eliminate outages caused during storms as a result of wind, ice, and falling trees. During both normal and severe weather conditions, consumers served by new underground distribution systems would continue to experience outages caused by load curtailments and damage to the transmission system, as well as a small number of outages to the new underground distribution system as a result of equipment failures and dig-ins.

On Virginia Power's distribution system during 2003, the interruption frequency[48] on underground facilities was approximately one-third[49] of the interruption frequency on

[45] The Staff did not attempt to quantify the existent, but much smaller, economic losses associated with the telecommunications outages that would be avoided by placing telecommunications lines underground.

[46] B. Johnson, *Out of Sight, Out of Mind? A Study on the Costs and Benefits of Undergrounding Overhead Power Lines*, Edison Electric Institute ("EEI Study"), January 2004; *Task Force to Study Moving Overhead Utility Lines Underground*, Report to the Maryland General Assembly, December 2003; *Putting Cables Underground: Applicable Principles of Public Finance*, The Allen Consulting Group Pty. Ltd., Consultancy Report to the Economic Sub-Committee of the Working Group on Putting Cables Underground, Australia, September 1997.

[47] North Carolina Feasibility Study, p. 17.

[48] Outage events per overhead pole mile or outage events per underground cable mile.

[49] Based on 1.32 outage events per pole mile of overhead distribution line compared with 0.40 outage events per mile of underground distribution cable.

overhead facilities.[50] The disparities were even greater on Potomac Edison's and Old Dominion Power's distribution systems.[51] Other utilities in Virginia do not collect and analyze outage data separately for underground and overhead distribution facilities.

Statistics regarding the duration of outages on underground facilities relative to outages on overhead facilities were inconsistent among the utilities reporting such information. In general, during normal weather conditions, the total system outage time for an underground distribution system should be less than the total system outage time for an overhead distribution system. This is particularly true when severe weather is factored in. For those specific customers who do experience an outage, the average outage time as a result of interruptions to underground facilities could be greater than that for interruptions to overhead facilities because underground interruptions can be more difficult to locate and repair.

An initiative[52] by the Electric Power Research Institute ("EPRI") and the Electricity Innovation Institute ("EII") suggests that across all business sectors, the U.S. economy is losing between \$104 billion and \$164 billion annually to electric power outages and power quality disturbances.[53] The study suggests that Virginia's economy is losing between \$2.7 and \$4.3 billion annually to electric power outages and power quality disturbances across all business sectors.[54] A significant portion of these economic losses can be attributed to interruptions affecting those business sectors that receive electricity at distribution level voltages. In addition, distribution related outages also result in economic losses for residential consumers, estimated by the Staff to be as much as \$20 million per year in Virginia. (The Staff's analysis of the economic losses for residential consumers is provided in Appendix E.) Conversion of overhead distribution facilities to underground would eliminate at most 80 percent [55] of these economic losses (i.e., \$2.2 to \$3.4 billion).

Implementing a program to convert overhead distribution facilities to underground in order to improve service reliability would be costly. Converting the entire electricity distribution system to reach a standard of reliability that costs more than consumers are willing to pay, or maintaining an overhead system that leads to more outages than customers are willing to bear, are both sub-optimal strategies. It is therefore

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[50] Refers to primary outages including major storms, except Isabel. Excludes secondary interruptions.
[51] The frequency of outages on underground facilities was approximately one-fifth that of overhead facilities during normal weather conditions. (The frequency of outages on Potomac Edison's underground facilities was approximately one-tenth that of overhead facilities if major storms, including Hurricane Isabel, are factored in.)
[52] D. Lineweber and S. McNulty (Primen), *The Cost of Power Disturbances to Industrial & Digital Economy Companies*, June 2001. (Projections to all business sectors represent Lineweber's and McNulty's extrapolations from the survey data.)
[53] As large as these numbers are, they reflect only the direct costs of outages to the individual businesses that experience them. They do not include any secondary costs incurred by one business as a result of an outage that occurs at another company's location. They also do not include the money that firms have already invested in products and services designed to avoid or mitigate the effects of outages. (Ibid., p. 3-11)
[54] \$2.4 - \$3.7 billion from electric power outages and \$0.3 - \$0.5 billion from power quality disturbances.
[55] Conversion of overhead distribution facilities to underground would not reduce economic losses resulting from outages attributable to bulk power, load curtailment, underground equipment failure or dig-ins.

important to understand how much improvements in reliability would cost consumers, as well as how much they would be willing to pay for such improvements, so that appropriate policies can be devised. It should also be noted that the implementation of a limited or gradual program would result in something less than the full economic annual benefits estimated above. More detailed analysis would have to be performed to determine if improved reliability, as a result of placing overhead facilities underground, would be cost effective for a specific circuit due to significant variations in cost.

"Hundred-Year" Storm Impact of Electric Power Outages on the Economy

Widespread consensus exists that placing distribution facilities underground would significantly reduce the lengthy power outages associated with "hundred-year" storms such as Hurricane Isabel. Such catastrophic storms result not only in lost revenues for utilities but also in both direct costs (due to lost production, lost wages, and food spoilage) and indirect costs (due to the secondary effects of the direct costs) to consumers. ICF Consulting[56] notes that one way to estimate the economic costs of a power outage is to calculate consumers' willingness-to-pay to avoid such outages.[57] Based on previous analyses, ICF Consulting estimates that the "value of electricity" to consumers (measured as their willingness-to-pay to avoid lengthy outages) is approximately 80-120 times the retail price of electricity. This model has been used by ICF Consulting to estimate the economic cost of the August 14, 2003, northeastern blackout on the order of $7-10 billion.

In order to calculate the total economic cost to the state from Hurricane Isabel, one would multiply the average "value of electricity" for the affected customers (including residential, commercial, industrial, and others) by the utilities' total lost sales of electricity. According to data provided by the Energy Information Administration, the September 2003 average electricity price in Virginia was 6.3 cents per kWh, and, therefore, the average "value of electricity" for the affected customers could be estimated to be $5,072 to $7,608 per MWH. The utilities' total lost sales of electricity as a result of Hurricane Isabel was around 450,000 MWH, based on a summation of the individual utilities' lost sales already provided above. Therefore, the cost to Virginia's economy from the power outages associated with Hurricane Isabel can be estimated to be $2.3 to $3.4 billion.[58] Assuming that no more than two such storms (one "hundred-year" hurricane and one "hundred-year" winter storm) would impact the state over the lifetime of the underground facilities, then placing all overhead facilities in the state underground could benefit Virginia's economy by as much as $4.6 to $6.8 billion, or approximately $150 to $230 million per year (in current dollars) in avoided costs assuming a 30-year life expectancy of the new underground system.

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[56] A management, technology, and policy consulting firm headquartered in Fairfax, Virginia.

[57] "The Economic Cost of the Blackout," ICF Consulting, An Issue Paper on the Northeastern Blackout, August, 14, 2003. http://www.icfconsulting.com/Markets/Energy/doc_files/blackout-economic-costs.pdf (12/16/2004)

[58] A small percentage of the economic costs of power outages from Hurricane Isabel were a result of damage sustained by transmission facilities and flooding of underground distribution facilities; however, the Staff has not attempted to quantify these costs that would not be eliminated by undergrounding.

Motor Vehicle Accidents Impact on the Economy

In 2000, the latest year for which data were compiled on a national basis, there were approximately 1,100 fatalities and about 60,000 injuries related to collisions with some of the 88 million utility poles located on highway roadsides.[59] The annual number of collisions with utility poles, and the costs associated with such collisions, could be reduced by converting overhead distribution facilities to underground. The National Safety Council ("NSC") makes estimates of the average costs of fatal and nonfatal unintentional injuries to illustrate their effect on the nation's economy.[60] The costs are a measure of the dollars spent and income not received due to accidents, injuries, and fatalities. It is another way to measure the importance of prevention work.

The NSC notes that the calculable costs of motor-vehicle crashes are wage and productivity losses,[61] medical expenses,[62] administrative expenses,[63] motor vehicle damage,[64] and uninsured employer costs.[65] Expressed on a "per death" basis, the average combined cost of all categories of motor vehicle crashes in 2003 – i.e. fatal, nonfatal injury, and property damage – was $5,410,000 per death.[66] According to the NSC, this figure would be appropriate only for measuring the economic loss to a community resulting from past motor-vehicle crashes; it should not be used, however, in computing the dollar value of future benefits due to traffic safety measures because it does not include the value of a person's natural desire to live longer or to protect the quality of one's life. That is, the economic loss estimates do not include what people are willing to pay for improved safety. According to the NSC, research has been done to create the necessary theoretical groundwork and empirical valuation of injury costs under the

[59] Fatality Analysis Reporting System, National Highway Traffic Safety Administration. As reported in "Utility Pole Collisions," C. Paul Scott (Federal Highway Administration) and Don L. Ivey (Texas Transportation Institute), *Utilities and Roadside Safety*, Committee on Utilities, Transportation Research Board of the National Academies, Washington, D.C., 2004.

[60] *Estimating the Costs of Unintentional Injuries, 2003*. Statistics Department, National Safety Council, and Children's Safety Network, Economics and Insurance Resource Center, Pacific Institute for Research and Evaluation, 23 September 2004, http://www.nsc.org/lrs/statinfo/estcost.htm,. (28 October 2004).

[61] Wage and productivity losses include the total of wages and fringe benefits together with an estimate of the replacement-cost value of household services. Also includes travel delay for motor-vehicle crashes.

[62] Medical expenses include doctor fees, hospital charges, the cost of medicines, future medical costs, and ambulance, helicopter, and other emergency medical services.

[63] Administrative expenses include the administrative cost of public and private insurance, and police and legal costs. Private insurance administrative costs are the difference between premiums paid to insurance companies and claims paid out by them. It is their cost of doing business and is part of the cost total. Claims paid out by insurance companies are not identified separately, as every claim is compensation for losses such as wages, medical expenses, property damage, etc.

[64] Motor-vehicle damage includes the value of property damage to vehicles from motor-vehicle crashes. The cost of normal wear and tear to vehicles is not included.

[65] Uninsured employer costs are an estimate of the uninsured costs incurred by employers and represents the money value of time lost by uninjured workers. It includes time spent investigating and reporting injuries, giving first aid, production slowdowns, training of replacement workers, and extra cost of overtime for uninjured workers.

[66] This is based on constant ratios of deaths to disabling injuries and deaths to property damage crashes. It includes the cost of one death, 54 nonfatal disabling injuries, and 223 property damage crashes (including minor injuries). This average may be used to estimate the motor vehicle crash costs for a state provided that there are at least 10 deaths and only one or two occurred in each fatal crash. If fewer than 10 deaths, NSC recommends estimating the costs of deaths, nonfatal injuries, and property damage crashes separately.

"willingness to pay" or comprehensive cost concept. The NSC explains further that estimates based on the “comprehensive” cost concept should be used for cost-benefit analyses wherever feasible.

In addition to the economic cost component of motor-vehicle crashes listed above, the comprehensive costs also include a measure of the value of lost quality of life which was obtained through empirical studies of what people actually pay to reduce their safety and health risks. In 2003 the average comprehensive cost on a per death basis was approximately $6,800,000.[67] According to statistics provided by the Virginia Department of Transportation (“VDOT”),[68] there were 22 deaths per year on average in Virginia over the five-year period 1999-2003 as a result of 20.4 fatal crashes per year with utility poles. In addition, VDOT reported 1,158 “injury” crashes and 1,564 “property damage only” crashes on an average annual basis over the same time frame. Using the comprehensive cost estimates for a “per death basis,” the average annual comprehensive cost of all motor vehicle crashes with utility poles in Virginia – i.e. fatal, nonfatal injury, and property damage – can be estimated to be $6,800,000 x 22 (average number of deaths per year), or approximately $150 million per year.

It is likely that most of the costs associated with motor vehicle crashes and utility poles could be eliminated by placing less than 100 percent of the overhead facilities underground, because some circuits (in back lot construction or some rural areas, for example) might not be vulnerable to such accidents. On the other hand, it is unlikely that all of the traffic accidents could have been avoided in the absence of the poles. In some cases, the accidents (and resultant comprehensive costs on the economy) likely would have occurred in any event, but instead of utility poles the accidents would have involved the trees, concrete walls, fire hydrants, parked vehicles, or traffic light posts that frequently exist next to these poles. Ideally, each locality or individual circuit should be analyzed with respect to the potential benefit to the local economy by placing overhead facilities underground and thereby avoiding the comprehensive costs associated with accidents involving motor vehicles and utility poles.

Summary

This section, *Analysis of Benefits to the Economy from Undergrounding*, addressed the primary potential economic benefits to the economy that might result if the currently existing overhead distribution facilities were to be placed underground. The three benefit categories that were addressed included avoided costs associated with reduced electric power outages on a day-to-day basis, avoided costs associated with electric power outages from “hundred-year” storms, and avoided costs associated with reduced vehicular accidents with electric and telephone utility poles. The next section, *Summary Review of Economic Costs and Benefits*, provides a summary and comparison of the previous results from the utility benefit/cost analysis and the analysis of the benefits to the economy.

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[67] Alan F. Hoskin, Manager of Research and Statistics, National Safety Council, telephone conversation with W.T. Lough, Special Projects Engineer, SCC, October 29, 2004.

[68] Email from R. Robert Rasmussen, II, Program Administration Manager III, VDOT, Mobility Management Division, October 28, 2004.

SUMMARY REVIEW OF ECONOMIC COSTS AND BENEFITS

Summaries of the "overnight" costs and the annualized costs and benefits are provided in the discussion below and tables that follow. The total "overnight" costs of relocating the currently existing overhead distribution lines to underground were estimated to be approximately $75 billion for the investor-owned electric utilities ("IOUs"), $8 billion for the electric cooperatives, and $11 billion for the telecommunications providers. (As mentioned elsewhere in this report, these cost estimates do not reflect a high level of confidence, but probably represent an upper bound. The IOUs' estimates include significant general and administrative overhead costs, as well as various contingency additions, which would tend to inflate overall cost estimates. On the other hand, some of the estimates did not consider certain issues that would tend to increase the estimates.)

The resultant levelized annual revenue requirements for the electric utilities alone would be approximately $10 billion. The annual levelized revenue requirement on a per customer basis would be approximately $3,000 per year. This result is based on an annual revenue recovery factor of 13 percent and a 30 year life of the facilities. Different assumptions would result in different calculations of the revenue requirements. Any impact on individual customers would depend on the rate design methodology.

The estimated levelized annual cost to customers might be more than residential consumers are willing to pay. For example, a small, informal, non-scientific survey by the Staff indicated that residential consumers on average might be willing to pay about $15 per month, or $180 per year, to underground the currently existing overhead distribution lines (see Appendix F). A more detailed valuation analysis should be undertaken to determine customers' willingness to pay for specific applications.

The total annual equivalent of savings and avoided costs to the electric utilities and the economy was estimated to be at most $3.9 billion, or approximately five percent of the total overnight cost. (Where a range of potential benefits was previously given, the upper end of the range was used in the table and to calculate the total benefit. In addition as explained in previous sections, the benefits are probably overstated because of the conservative assumptions used in some of the estimates. It may be that some of the benefits have been double counted, as well.) By way of comparison, the Australian Underground Working Group found that the quantifiable benefits represent around 10 per cent of the total cost. According to the Australian Underground Working Group, the main quantifiable potential benefits of putting cables underground include possible savings in maintenance costs for telecommunications carriers and electricity distributors, savings in tree pruning costs and reduction in motor vehicle collisions with poles. Other benefits, not readily quantifiable, involve improved streetscape aesthetics from the removal of poles and wires and additional tree planting.

The Staff's determination, that the reduction in O&M costs resulting from placing overhead facilities underground could be insignificant, warrants additional, repeated explanation. As explained previously, the Staff believes that the impact on overall O&M costs of placing overhead distribution facilities underground would not be significant on a statewide basis. Although tree-trimming, outage restoration and vehicular-accident related O&M costs can be nearly eliminated by placing overhead facilities underground, non-trimming/non-accident O&M costs could increase since such costs are often higher for underground facilities than for overhead facilities. Nevertheless, the Staff has included the potential savings from reduced tree-trimming as a benefit in the following table. The O&M costs and benefits will be different for each individual utility or underground application, therefore individual projects need to be analyzed on an individual basis.

"Overnight" Costs	**Electric IOUs**	**Electric Cooperatives**	**Telecommunications**
Total Costs	$75,085,000,000	$8,300,000,000	$10,600,000,000
Total Customers	2,726,000	411,000	4,500,000
Total Overhead Miles	62,830	34,000	46,000
Average Cost Per Mile	$1,195,000	$200,000	$230,000
Ave. Cost Per Customer	$27,000	$20,000	$2,400
Note: The numbers in this table have been rounded and are approximate			

Electric Annualized Costs and Benefits (1)	**Economic Costs**	**Economic Benefits**
Cost Categories:		
Levelized Annual Revenue Requirement	**$10,400,000,000**	
Utility Benefit Categories:		
Operations & Maintenance Savings (2)		Negligible
Tree trimming Savings		$50,000,000
"100-Yr" Post Storm Rebuild		40,000,000
Avoided Sales Lost in Day-to-Day Outages		12,000,000
Avoided Sales Lost in "100-Yr" Storms		2,000,000
Economy Benefit Categories:		
Avoided Impact of Day-to-Day Outages		$3,440,000,000
Avoided Impact of "100-Yr" Storm Outages		230,000,000
Avoided Impact of Motor Vehicle Accidents		150,000,000
Total Annual Benefit to Utility and Economy		**$3,924,000,000**
Notes: (1) The numbers in this table have been rounded and are approximate. This table does not include telecommunications/CATV costs or benefits (2) O&M includes day-to-day service restoration costs but excludes tree-trimming costs.		

DISCUSSION OF ADDITIONAL ELECTRIC AND TELECOMMUNICATIONS/CATV IMPACTS & FEASIBILITY ISSUES

Aesthetics

The aesthetic appearance of underground utility facilities is generally accepted as better than that of comparable overhead facilities. However, underground facilities do not completely eliminate all visual impacts in all areas. For example, the transformers used in underground applications are typically mounted on pads above ground in most subdivisions. In some applications, it might be necessary to replace back-lot aerial facilities with street-side underground facilities. The aesthetic benefit should be considered from an environmental preservation perspective and from the human perspective of the impact on quality of life. Aesthetics was mentioned by the interested parties in this study as an important criterion for determining whether utility distribution lines should be placed underground. The interested parties noted also that underground facilities do not interfere with natural tree growth and enable pedestrian friendly walkways.

The Australian Underground Working Group noted that aesthetics could be one of the primary urban benefits to putting cables underground. It noted, however, that it also is one of the hardest benefits to quantify as it is "intangible, not separately tradable, var[ies] greatly from area to area and [is] dependent on people's individual perceptions." The Working Group noted that a survey could be conducted to determine how much individuals might value the putting of cable underground in their area; however, the Working Group concluded that it would not attempt to undertake a national valuation of these otherwise unquantifiable benefits. The Working Group reasoned that, as well as being very expensive, such approaches may not in any case lead to results that would have widespread credibility.[69]

To the extent the relocation of lines is not cost justified, aesthetics might be the primary reason to undertake such an initiative. The possible tax consequences of such a determination should be considered as part of any relocation program. Additional discussion of the tax consequences associated with contributions in aid of construction is provided in the following subsection.

CIAC

Regulated public utilities have historically received subsidies or contributions from nonshareholders such as customers or developers to help finance the expansion or improvement of capital facilities. Prior to the Federal Tax Reform Act of 1986 ("the Act"), these subsidies were considered nontaxable contributions to capital, and were excluded from the gross income of the corporation for income tax purposes. However, the Act provided that all contributions in aid of construction ("CIAC"), or any other

[69] *Putting Cables Underground Working Group Report*, Commonwealth of Australia, 1998, Chapter 4, Section 4.15, Unquantifiable Benefits.

contributions by a customer or potential customer, are includible in gross income of the receiving corporation.

The U.S. House of Representatives Ways and Means Committee Report ("House Report") for the Act explains that property, including money, is a CIAC if it is contributed to provide or encourage the provision of services to or for the benefit of the person making the contribution. A utility has received property to encourage the provision of services if any one of the following conditions are met: the receipt of the property is a prerequisite to the provision of the services; the receipt of the property results in the provision of services earlier than would have been the case had the property not been received; or the receipt of the property otherwise causes the transferor to be favored in any way. Payment to a utility will be treated as a CIAC whether the payment is direct or indirect. For example, a utility will be taxed on a CIAC regardless of whether the customer engages the services of an unrelated contractor to construct the property to which the CIAC relates or whether the customer instead directly pays the CIAC to the utility with the utility itself assuming responsibility to construct the related property. The property is includible in the utility's gross income to the extent of the property's fair market value.

The House Report also states that transfers of property are not CIAC if they are not made in connection with the provision of services, including situations where it is clearly shown that the benefit of the public as a whole was the primary motivating factor in the transfers. In such cases, the property received may be treated as a contribution to the capital of the taxpayer and excludible from gross income. An example of a payment benefiting the public at large is a relocation payment received by a utility under a government program to place utility lines underground. In that situation, the relocation payment is not considered a CIAC where the relocation is undertaken for either reasons of community aesthetics or in the interest of public safety and does not directly benefit particular customers of the utility.

The taxation of CIAC serves to increase the cost of new facilities that will ultimately be borne by consumers. However, regulatory authorities may decide not to allow a utility to increase rates of the general body of ratepayers to provide for the specific benefit of a particular group of customers, and may therefore allow a utility to directly charge the contributor for this additional tax. The State Corporation Commission has allowed utilities under its jurisdiction to gross-up CIAC's by a Tax Effect Recovery Factor (TERF) to provide for recovery from the contributor of this net increase in taxation. The TERF recognizes the current federal income tax consequences of the contribution to the utility, less the present value of future income tax savings generated by the associated tax depreciation benefits. Since the contributor bears the tax consequences under this procedure, rates charged to the general body of ratepayers are unaffected by the CIAC. However, the escalation of the CIAC cost may result in the development of new facilities to be judged uneconomic.

Payments received by a utility for undergrounding of existing overhead electric distribution lines may be found to be nonshareholder contributions to the capital of the utility and not taxable as CIAC's. If the undergrounding is found to be mandated by applicable laws and is undertaken for purposes of community aesthetics or public safety and will generally benefit the public at large, it may be determined that such contributions are excludable from income for tax purposes. However, the legislative and judicial histories of the tax principles in this area are very complex and often confusing and inconsistent. Absent a specific ruling by the IRS, it is uncertain how nonshareholder contributions for placing underground the existing overhead utility distribution lines would ultimately be treated.

According to the Maryland Task Force Report, the costs of undergrounding projects in Maryland that are not considered a public benefit are "grossed-up" so that utilities may recover (up-front, from the beneficiaries of the undergrounding project) the costs that are incurred as a result of the tax. For projects that are considered to be for public safety or a public benefit, typically those projects along public roads and highways, payments are not considered CIAC and therefore not taxable. For projects being completed for individuals primarily to improve aesthetics, the tax is applicable. In the Maryland Task Force Report, the Task Force recommended that the Maryland Attorney General should solicit an opinion and clarification from the Internal Revenue Service on the applicability of the tax on contributions in aid of construction.[70]

The Commission Staff is aware of one state that has established law relative to the public benefit of underground utility lines which may or may not be relevant to the CIAC issue. According to an Hawaiian report[71] on undergrounding public utility lines, the State of Washington legislature determined that the conversion of overhead electric and communication facilities to underground facilities and the initial underground installation of such facilities is substantially beneficial to the public safety and welfare, is in the public interest and is a public purpose, notwithstanding any resulting incidental private benefit to any electric or communication utility affected by such conversion or installation.[72]

Underground Damage Prevention

Relocating all existing overhead utility distribution lines underground could significantly impact Virginia's underground damage prevention program depending on the time horizon for completion of the relocation initiative. If the relocation initiative were to be completed over a relatively short construction period, the impact on the Miss Utility process would be substantial. The state's Miss Utility One-Call Center might have to be expanded in order to handle the anticipated increase in calls as a result of such an

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[70] According to the Maryland Task Force Report, 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. p.5.

[71] *Undergrounding Public Utility Lines*, Legislative Reference Bureau, Honolulu, December 1999, p.33.

[72] Section 36.88.410 Revised Code of Washington (Chapter 36.88, County Road Improvement Districts); see also Section 35.96.010 RCW (Title 35, Cities and Towns, Ch. 35.96, Electric and Communication Facilities – Conversion to Underground).

initiative. The companies responsible for locating and marking all of the existing underground utilities would have to increase staff to deal with the increased location requests. The direct cost to the utilities would be the costs of giving notice to the Miss Utility One-Call Center (currently $1 per notice) and the costs of locating the underground facilities (on the average about $10 per locate). In addition, the increased excavation activities would likely result in an increase in physical damage (dig-ins) to existing facilities. The costs of dig-ins include not only the repair cost but also the costs associated with personal injuries and deaths that can result from such accidents.

Right-of-Way Acquisition

The relocation of overhead distribution lines to underground raises potential issues with respect to the attainment of new easements. While some overhead easements may contain provisions to allow the installation of underground facilities, others may not contain such provisions, potentially resulting in the need to obtain easements from numerous individual property owners. Permits might also be required for railroad and highway crossings. This can be a costly and time-consuming process. Utilities anticipate a need for a substantial increase in resources to handle indemnification, legal issues, eminent domain issues, property owner identification, and the procurement of such easements.

In areas where overhead lines span wetlands, bodies of water or rough terrain, relocation over existing routes might not be suitable, in which case different, longer routes would be required. This could increase construction costs.

When overhead to underground utility conversion projects are designed in heavily urbanized areas, space is not available for an unimpeded utility corridor; therefore, right-of-way limits cannot be determined until designs are finalized. Conduit systems must be designed to snake through existing utilities while keeping proper clearances between them. Right-of-way needs are identified based upon final plans. Arlington County identified five factors, summarized below, that it believes can combine to make the process of acquiring rights-of-way "frustratingly slow:"

- Acquisitions cannot begin until a relocation project is fully designed and ready to construct. It would be much more efficient if there were some standard width or location for utility service, so right-of-way acquisitions could occur concurrently with design.

- Utility companies note that "standard service" consists of overhead lines which provide adequate service. Arlington believes that utilities are therefore not motivated to aggressively pursue rights-of-way for relocation projects. This requires Arlington County staff to secure most underground rights-of-way for utility companies if they want a project to proceed to construction.

- Modifications must be made to the interior of every building when utility service is converted from overhead to underground. Separate permission must be secured to work inside homes or businesses. A private electrician must be hired, permits secured, and work directed, adding to the general complexity of the project, which is often coordinated by Arlington County staff.

- There is limited above-ground space for utility pad mounted boxes (switches, transformers, etc.) associated with utility undergrounding. Boxes are not small, typically six feet long, eight feet wide, and four feet tall. A large open area is required around each box allowing access doors to be opened and switches to be thrown during storms.

- Arlington County is an urban community where land can be very valuable. The pad mounted utility structures are considered bulky, unattractive, and take a lot of space, so these structures are typically unwanted by many property owners.

Any relocation project faces the possibility of acquiring new easements, which can be a time-consuming and costly process. Some utilities and localities believe a streamlined approach to acquiring easements would be needed for a comprehensive relocation initiative, or the cost and time associated with the effort would be prohibitive.

Operational Impacts[73]

An overhead distribution system is more flexible than an underground system. For example, tapping an overhead line to serve additional load is a relatively easy and low-cost task. It involves making an electrical connection to the line, running additional wire to the desired transformer location, and installing a new transformer. Tapping an underground cable is much more complicated, time consuming, and costly. The cable must be cut and spliced somewhere along the loop, followed by the installation of complex rubber insulated elbow connectors to tie into the transformer. The new cable must be buried as well.

Reconfiguration is a continual and fairly simple process with overhead distribution. As load grows, portions of circuits are frequently “switched over” to adjacent circuits to help balance the loads, delaying the need for additional lines and substations. With underground distribution, open points and terminations in the system are fixed, and it is usually extremely difficult to alter the original arrangement. Similarly, since most “taps” or branch circuits usually start out as single-phase circuits, it is quite common to serve load growth by adding an additional phase or two (i.e., by installing crossarms and additional wire) to overhead circuits. With underground circuits, it is much more difficult and expensive to go back and install additional cable.

In addition, most underground crews receive specialized training in splicing and terminating cable, and most utilities maintain underground crews whose specialty is locating cable faults. These crews receive extensive training on fault locating equipment. Because this equipment continues to evolve, training is an ongoing process.

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[73] Much of this discussion is taken from the North Carolina Feasibility Study.

According to one utility, circuit sectionalizing and protection will be more difficult to achieve on very long circuits that are buried completely underground. In addition, long underground circuits are naturally capacitive due to the material characteristics of the cable, which can result in abnormally high voltages. Extensive transmission and station infrastructure additions might be necessary to fragment the existing distribution system to overcome the sectionalizing and protection and cable capacitance issues.

Although underground cable can complicate certain aspects of operations, the complications are not insurmountable. Nevertheless, in evaluating any relocation project, the operational issues and associated costs need to be considered.

Local Authority Regarding Undergrounding

One issue raised by the interested parties concerned whether or not localities had specific authority to require undergrounding or to impose taxes to pay for undergrounding. There was no consensus among the interested parties on this issue, and summaries of their comments are provided in the responses to generic questions 9, 10, and 11 in Appendix C. The following paragraphs provide a summary of the Staff's research relative to this issue.

There appears to be language in the Code of Virginia that enables localities to require the undergrounding of *new* facilities, pursuant to the subdivision ordinance authority found at subdivision 4 of § 15.2-2241 of the Code of Virginia. The phrase "and other public utilities" may be construed to encompass electric and telephone utility facilities.

There does not appear to be any explicit authority in the Code enabling localities to require the undergrounding of existing facilities. There is, however, the possibility that § 15.2-2403 of the Code of Virginia (regarding the establishment and power of "service districts") could be so broadly construed to provide some authority for localities to establish service districts within which existing facilities must be undergrounded (for instance, for "beautification" purposes, or to "enhance the public use and enjoyment of and the public safety, public convenience, and public well being …," all of which are specifically mentioned in subdivision 1 of § 15.2-2403 of the Code of Virginia.

It is less certain that localities have the authority to impose taxes or assessments upon the owners of property that abut undergrounded facilities: § 15.2-2404 of the Code of Virginia allows only a city with a population between 11,200 and 12,000 (Williamsburg) to impose such cost recovery mechanisms, excluding all other localities that are not cities with between 11,200 and 12,000 residents.

CONCLUSIONS OF PREVIOUS STUDIES

<u>2004 Edison Electric Institute Report</u>[74]

Placing existing power lines underground is expensive, costing approximately $1 million per mile. This is almost 10 times the cost of a new overhead power line.

While communities and individuals continue to push for undergrounding – particularly after extended power outages caused by major storms – the reliability benefits that would result are uncertain, and there appears to be little economic justification for paying the required premiums.

. . . .

For the foreseeable future, however, it appears that the undergrounding of existing overhead power lines will continue, justified primarily by aesthetic considerations – not reliability or economic benefits. Many consumers simply want their power lines placed underground, regardless of the costs. The challenge for decision makers, is determining who will pay for these projects and who will benefit.

There are several undergrounding programs around the country that are working through these equity issues and coming up with what appear to be viable compromises. Once a public-policy decision is reached to pursue an undergrounding project, it is worthwhile for the leaders involved to evaluate these programs in more detail to determine what is working, and what is not.

<u>2003 North Carolina Feasibility Study</u>[75]

Based on the results of its investigation, the Public Staff concludes that it is not feasible to replace the existing overhead distribution power lines constructed by Duke, Progress Energy, and Dominion with underground power lines at this time. Such an undertaking would cost approximately $41 billion[76] and require 237 million man-hours to complete. This represents nearly a six-fold increase in current distribution assets of $7.36 billion. It would take a construction work force of nearly 5,000 employees 25 years to complete the project and, in the end, result in an $8.8 billion annual revenue requirement or an increase in rates of 10 cents per kWh, assuming the costs are spread uniformly to all customers.

The estimated conversion costs should be considered a minimum or a starting point, as they do not include other costs that are not quantified in this report but nevertheless would exist. In addition, there are higher costs to operate and maintain an underground system, which ultimately would be borne by the customer. While the O&M costs on a per mile basis for overhead systems and direct-buried underground systems are comparable, the O&M costs of underground systems with duct banks are almost four times more than that of overhead systems. Duct bank construction is needed in large

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[74] EEI Study, p. 18.
[75] North Carolina Feasibility Study, November 2003, pp. 39-41.
[76] The North Carolina estimate did not include the cost to bury individual services or estimates from electric cooperatives or telecommunication providers.

cities to handle commercial loads where conductors are placed on concrete duct banks and transformers are located in underground vaults.

The reliability of underground systems during normal weather conditions is better than overhead systems. Underground systems experience about half as many system interruptions and tap line interruptions as overhead systems. This gain in reliability, however, is offset by a 58 percent increase in repair time, as underground faults require specialized repair crews to locate the faults, dig up the area around the fault, and repair the cable. In most cases, such an effort requires different crews and scheduling. During severe weather events, customers with underground facilities are less likely to be interrupted but will be among the last to have power restored when there is an underground fault.

The Public Staff believes the wisest course of action in view of these results is for the Utilities to continue their current practices of (1) adding new facilities underground when it is economical to do so or when the cost difference is paid by the customer or developer requesting the new underground service, (2) replacing existing overhead facilities with underground on a case-by-case basis upon request when the requesting party pays the conversion costs, and (3) replacing overhead facilities with underground facilities in urban areas where factors such as load location and physical congestion make service impractical from overhead feeders.

The Public Staff also believes, however, that each of the Utilities should (1) identify the overhead facilities in each region it serves that repeatedly experience reliability problems based on measures such as number of outages or number of customer-hours out of service, (2) determine whether conversion to underground is a cost-effective option for improving the reliability of those facilities, and, if so, (3) develop a plan for converting those facilities to underground in an orderly and efficient manner, taking into account the outage histories and the impact on service reliability. Such a plan might include a policy similar to that of Dominion Virginia Power of annually identifying the "worst 10 circuits" and "worst 10 devices" in each of its regions and taking appropriate steps to improve or replace each of these circuits and devices.

2003 Maryland Task Force Report[77]

Chapter 179 Acts of 2002 established the Task Force to Study Moving Overhead Utility Lines Underground.

. . . .

. . . 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;*

[77] Maryland Task Force Report, pp. 5, 6.

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

1998 Australian Working Group Report

In concluding its examination the working group notes that it is not possible to provide accurate information for every possible project to put cables underground, and that each project should be considered on its own merits.[78]

[78] *Putting Cables Underground Working Group Report*, Commonwealth of Australia, 1998, "Conclusion" in Executive Summary and Key Findings.

SCC FINDINGS REGARDING THE FEASIBILITY OF UNDERGROUNDING

New Circuits

1. The placement of new circuits underground in many applications is reasonable.
2. As a matter of current practice, the percentage of new circuits being placed underground has been as much as 97 percent for some applications, such as new residential subdivisions in DVP's territory, but not as high for other applications.
3. Unit costs can vary substantially depending on natural and physical obstacles, facility type, and type of underground system required, making some applications more reasonable than others.
4. All utilities allow developers/customers to request underground service for new developments and have established cost-recovery policies according to approved tariffs on file with the SCC.
5. There appears to be language in the Virginia Code that enables localities to require the undergrounding of *new* facilities, pursuant to the subdivision ordinance authority found at subdivision 4 of § 15.2-2241 of the Code of Virginia.
6. Many localities have local ordinances that require the placement of new circuits underground in new residential subdivisions.
7. In responses to a questionnaire submitted by Commission Staff to all state public service commissions in July 2004, Alaska, Arizona,[79] California, Delaware,[80] Michigan,[81] Montana,[82] New Jersey,[83] New York,[84] and Pennsylvania[85] noted that

[79] Arizona's Electric Rules require extensions of single phase electric lines necessary to furnish permanent electric service to new residential buildings or mobile homes within a subdivision to be installed underground except where it is not feasible from an engineering, operational, or economic standpoint. (R14-2-207E)

[80] Delaware state law reportedly requires distribution service to any subdivision of five or more residential lots to be placed underground. (Letter from Robert J. Howatt, Public Utilities Analyst, DPSC, 8/11/04)

[81] Michigan Administrative Code generally requires extensions of residential and commercial distribution and service lines in the lower peninsula mainland to be placed underground, and the owner or developer to pay a contribution in aid of construction equivalent to the difference between overhead and direct burial underground facilities. The public service commission can grant relief when in the public interest. (see MIAC R 460.512 – 460.519)

[82] Montana Code Annotated requires distribution lines in new subdivisions of five or more residential or commercial units to be placed underground when technically and economically feasible. (see MCA 69-4-102) Montana Administrative Rules define "technical feasibility" as the ability to excavate by conventional backhoe or trencher and parcels not greater than five acres. Projects are defined as "economically feasible" if the underground cost per unit is no more than twice the overhead cost per unit. (see ARM 38.5.1001)

[83] New Jersey Administrative Code generally requires extensions of electric distribution lines necessary to furnish an electric system to new residential subdivisions having three or more building lots, or to new multiple-occupancy buildings to be placed underground. (see NJAC 14:5-4.1a) The applicant for the distribution system is required to pay the utility the differential cost between the construction of an underground and equivalent overhead distribution system. (see NJAC 14:5-4.4f)

[84] New York Code generally requires distribution lines to be placed underground in new residential subdivisions of five or more new buildings if no more than 200 feet of trench feet per dwelling unit is

either state laws or other regulations require new distribution lines to be placed underground in certain applications.[86] Maryland, which did not respond to the questionnaire, also requires that all utilities be placed underground in new subdivisions.[87]

Existing Circuits

1. A comprehensive, statewide initiative to relocate all currently existing overhead circuits does not appear to be reasonable;[88] however, targeted relocation programs have been initiated in some instances at the local level.[89]

2. Virginia's investor-owned electric utilities, electric cooperatives, telecommunications providers, and other interested parties[90] to this study generally do not support a comprehensive, statewide relocation initiative.

3. The very high costs associated with relocation programs, and the taxes or utility rates necessary to fund such programs, could have significant impacts on all consumers and might exceed the average consumer's willingness to pay in most cases.

4. The avoided costs that accrue to the utilities[91] and the economy[92] do not appear to offset initial construction costs in most cases. Any reduction in the scope of a relocation initiative, for the purpose of reducing initial construction costs, will result in a concomitant reduction in the potential benefits to be realized.

5. Based on its research and survey of states, the Staff is not aware of any state that has mandated a statewide conversion of overhead utility distribution lines to underground, although some municipalities have. Staff is aware of only one state, California, in which the PUC requires all investor-owned utilities to allocate a portion of total revenues for the purpose of relocating existing overhead circuits to underground.

6. Relocation of certain circuits, though still costly, could result in above average benefits (avoided costs) or have high public support, and therefore localities should have the ability to implement undergrounding programs in their areas.

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planned, or a governmental authority having jurisdiction has required undergrounding, or an applicant requests it. (see 16 NYCRR Part 100)

[85] Pennsylvania Code generally requires distribution and service lines installed under an application for electric service within a planned development of five or more adjoining unoccupied residential lots to be installed underground. The applicant is required to provide the excavating and backfilling. The Commission may grant exceptions. (see 52 PA Code Sections 57.81-57.88)

[86] A total of 41 states and D.C. responded. North Carolina, South Carolina, Georgia, Tennessee, Kentucky, and Ohio were among the nearby states that do not have a statewide requirement. West Virginia did not respond.

[87] Maryland Task Force Report, p. 1.

[88] Multiple previous studies support this finding generally.

[89] For example, Williamsburg, Alexandria, and Arlington.

[90] Based on a consensus of the interested parties attending the kickoff meeting of August 16, 2004.

[91] Increased sales, reduced tree trimming costs, and reduced restoration costs.

[92] Reduced blackouts and elimination of vehicular accidents.

7. Where conversion programs have been implemented locally, the time horizons for completion are frequently on the order of 50 years.

8. All utilities allow developers/customers to request relocation to underground service in accordance with company policies or approved tariffs. Generally, when adequate overhead facilities are replaced by new underground service, customers pay the cost to remove the overhead facilities, the undepreciated value of the overhead facilities net of salvage value, and the full cost of the new underground facilities. Policies might vary slightly among utilities and depending on specific circumstances.[93]

9. Interested parties to this study have suggested as follows that the feasibility of converting specific circuits to underground might be enhanced by increased utility cooperation with localities and developers, ensuring projects generally benefit the public at large, coordination among different utilities, and new legislation:

   - Some localities have complained that utilities are not particularly responsive, principally with respect to providing assistance obtaining easements.

   - Unless relocation projects are determined to benefit the public at large, contributions in aid of construction ("CIAC") may be subject to income taxes. The taxation of CIAC serves to increase the cost of new facilities that will ultimately be borne by consumers. Some utilities gross-up CIAC's by a Tax Effect Recovery Factor ("TERF") to provide for recovery of the cost of this tax treatment from the contributor. This policy could result in a determination by the developer/customer that a relocation initiative is uneconomic.

   - Improved coordination among different utilities and co-locating facilities in joint trenches might facilitate the process and lower costs in some applications.

   - There does not appear to be any explicit authority in the Code of Virginia enabling localities to require the undergrounding of existing facilities. There is, however, the possibility that § 15.2-2403 of the Code of Virginia (regarding the establishment and power of "service districts") could be so broadly construed to provide some authority for localities to establish service districts within which existing facilities must be undergrounded (for instance, for "beautification" purposes, or to "enhance the public use and enjoyment of and the public safety, public convenience, and public well being …," all of which are specifically mentioned in subdivision 1 of § 15.2-2403 of the Code of Virginia.

[93] In the case of the replacement of facilities providing inadequate overhead service, the cost is typically just the difference between new overhead installation and new underground installation.

FINDINGS REGARDING THE COSTS AND BENEFITS OF UNDERGROUNDING

1. Based on estimates submitted by the utilities, the total "overnight" cost of relocating the currently existing overhead distribution lines to underground was estimated to be greater than $90 billion. The estimates categorized by utility sector were approximately $75 billion for the investor-owned electric utilities, $8 billion for the electric cooperatives, and $11 billion for the telecommunications/CATV providers.

2. The potential savings for the utilities and the economy from relocating the currently existing distribution lines to underground (associated with a reduction in costs due to tree trimming, power outages and vehicular accidents) do not appear to offset initial construction costs in most cases.

3. The levelized annual revenue required by the electric utilities to finance a comprehensive statewide relocation initiative on a per customer basis would be approximately $3,000 per year.

4. Co-location of different types of cabling in joint trenches represents a potential opportunity to reduce the cost and disruption associated with putting cables underground in many cases. However, co-location reportedly also sometimes presents significant technical, safety, contractual and regulatory challenges which, in some cases, can substantially reduce or even negate the net benefits of co-location.

5. The economic costs and benefits used in this study were based on estimates (as opposed to detailed engineering studies) provided by the utilities or obtained from various other outside sources. The estimates were sometimes incomplete or inconsistent, were based on simplifying or qualifying assumptions, contain a significant amount of uncertainty, and can not be independently verified by the Staff. As such, the Staff is unable to assign a particular level of confidence to these estimates. Actual costs would be highly case specific and may vary substantially from these estimates.

FINDINGS REGARDING FUNDING OPTIONS FOR UNDERGROUNDING

Introduction

In order to explore the potential options for funding the relocation of overhead distribution lines to underground, the Staff conducted a literature search of previous studies and compiled comments from members of the public and other interested parties. Among the literature reviewed by the Staff, the most exhaustive list of potential funding options was developed for the Commonwealth of Australia in 1997 in response to legislation to study the feasibility of placing cables underground.[94] The Australian list of 48 possible funding options (some of which would not be applicable to the United States) is reproduced in Appendix G. As a result of the Staff's research and input from interested parties, the funding options listed in the next subsection were deemed to be most viable. In addition, the Staff has summarized four multi-contributor funding schemes that have been implemented or proposed elsewhere.

Simple Funding Options

The simple funding options listed below would be funded directly by consumers, utilities, developers, other businesses, or governments; however, ultimately, the costs will be paid by consumers, either directly or indirectly, in the form of prices, taxes, or utility rates. The costs could be (a) paid by those consumers who are directly affected by a specific conversion project, (b) subsidized by a wider group of consumers (general taxpayers or ratepayers that already have underground service, for example), or (c) paid by some combination of the two. Avoided costs, such as those associated with improved reliability (reduced restoration costs) and reduced impact on the economy (reduction of vehicular accidents), would reduce the cost to the consumer to the extent they are assigned to applicable utilities or governments.

Taxes or user fees. Examples of taxes include income taxes, sales taxes, meals taxes, room taxes or personal property taxes. There are a number of possible options for using taxes to fund the relocation of overhead distribution facilities to underground. The use of general revenues from federal and state taxes might be appropriate in the event of a national or statewide policy to relocate overhead facilities to underground. To the extent such taxes were used to fund only avoided costs (i.e., savings to the state or federal economies), no increase would be necessary, theoretically.

Some localities have created special taxing districts to impose special taxes or assessments for local undergrounding projects. Localities in Virginia apparently can levy special assessments for utility undergrounding only if they obtain express authorization from the General Assembly. Utility taxes as a result of franchise agreements between utilities and localities are another means for funding undergrounding projects.

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[94] The Australian *Telecommunications Act 1997* (Clause 49 of Schedule 3) provides that the Commonwealth Minister for Communications must cause an investigation of options for putting telecommunications and other facilities such as electricity infrastructure underground.

Municipal bonds are debt obligations issued by states, cities, counties and various districts to raise money to pay for projects for the public good. Municipal bonds issued for undergrounding projects are typically paid for by various taxes and property assessments. A portion of the bonds conceivably could be paid for via private donations (in the form of cash or rights-of-way) from businesses and developers.

Taxes also ultimately fund government grants such as the HUD community development block grants and guaranteed loans to local governments for revitalization programs, which potentially could be used to pay for small undergrounding projects.[95] In addition, some federal or state transportation funding might be possible in some cases.[96]

Utility rates. In the event the federal or state government mandated a comprehensive statewide conversion of overhead distribution facilities to underground, funding by a general rate increase or surcharge prior to expiration of rate caps would be open to question and subject to the provisions of the Restructuring Act. To the extent utilities' revenues were used to fund only an amount equivalent to the utilities' costs that would be eliminated by placing lines underground (certain post storm restoration costs, for example), no increase would be necessary, theoretically.

General policies with respect to utility rate design that limit the socialization of the costs associated with specific local conversion projects have been established in at least two states. While not binding on other states, the Staff notes two instances (one referenced in the Maryland Task Force Report[97] and the other in the North Carolina Feasibility Study[98]) where a court of appeals reportedly upheld a public service commission's ruling that the costs associated with undergrounding distribution lines in a specific locality were not eligible for general rate base treatment, but had to be borne fully by only those consumers receiving the benefit.

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[95] The City of Suffolk, Virginia, was awarded a $642,000 guaranteed loan fund in 2003 for street improvements including undergrounding utilities along Liberty and County Streets for a distance of 150 feet north and south of East Washington Street. (HUD Section 108 Loan Guarantee Program)

[96] VDOT's cost share policy for the placement of aerial utility facilities underground pertains to urban transportation projects only. The local governing body must have in place an ordinance or regulation establishing an underground corridor or area. The shared cost responsibility provides for a 50%-50% split between VDOT and the locality for the cost of placing the utility facilities underground, less the theoretical overhead relocation pro-rated cost between the utility company and VDOT, with a maximum shared cost obligation to VDOT not to exceed $5,000,000 (except for the Cities of Newport News and Hampton where VDOT is responsible for all costs below $5,000,000). VDOT also notes that some federal Transportation Enhancement funds (Transportation Equity Act for the 21st Century) have been used to share the cost of placing utility facilities underground. (Email, Chief Engineer, VDOT, December 7, 2004.)

[97] A 1987 ruling by the Maryland Court of Special Appeals upheld the Maryland PSC's finding that Annapolis's relocation costs were chargeable only to Annapolis customers and were not eligible for rate base treatment. (Maryland Task Force Report, p. 3.)

[98] A 1985 ruling by the North Carolina Court of Appeals upheld the North Carolina PUC's finding that the Roanoke Voyages Corridor Commission could not require Virginia Power to provide underground service on Roanoke Island as an operating expense which would be passed on to the general body of ratepayers. (*State ex rel. Utilities Commission v. Roanoke Voyages Corridor Commission*, 76 N.C. App.324, 332 S.E.2d 753 (1985), referenced in the N.C. Feasibility Study, pp. 37-39)

Cost recovery specific to telecommunications. As was briefly discussed in the Ocean View Case Study section of this report, it is important to consider the potential competitive ramifications of funding undergrounding projects, particularly when discussing funding through general utility rate increases or surcharges.

First, in the case of Virginia's largest telecommunications providers, Sprint and Verizon, the ability to increase rates is limited by the companies' current participation in alternative regulatory plans. These alternative regulatory plans cap prices, rather than earnings, and, as such, contain no provisions for rate increases designed to recover costs for non-company initiated projects such as undergrounding. In addition, under current Commission rules, competitive telecommunications providers, such as Cox, cannot increase rates above those of the traditional incumbent provider (e.g., Verizon), should the cost recovery associated with undergrounding necessitate such an increase. While there exists a waiver provision of this rule, one would have to surmise that the competitive provider might be placed in a competitive disadvantage should this scenario be realized.

Second, for those companies with tariffs that allow for a special surcharge or fee to be assessed on customer bills for municipality-initiated undergrounding projects,[99] careful consideration should be given to the competitive ramifications of such. For example, if Verizon were required to collect a fee to recover a locality's cost of undergrounding overhead facilities and its non-facilities-based competitors (i.e., resellers) were not, then Verizon might be placed in a competitive disadvantage. Moreover, it has been reported that wireless telephones may have already surpassed their wireline cousins in number. Some even suggest that wireless telephony is no longer complimentary to wireline telephone service, but that it is now a form of substitute technology. In other words, wireless technology is becoming a competitive threat to wireline telephone service. Accordingly, since wireless calls use the same wires as do wireline calls, at least in the case of intermodal calls,[100] it would seem logical that any special assessments would be made against wireless subscribers as well. While just in the emerging stages of development, there is also the growing use of voice over Internet protocol ("VoIP") as a substitute for wireline telephony, which may further complicate any billing surcharge used to recover undergrounding costs.

In the final analysis, should the decision be made to achieve cost recovery through customer billing, it would seem that any special assessments should be spread equally among all providers of telecommunications services, not just those with the physical facilities, to avoid creating competitive advantages and disadvantages among the various providers.

[99] Verizon Virginia (Bell Atlantic) and Sprint Central have such a tariff. Verizon South (GTE) and Sprint United do not.
[100] Wireless to wireline and vice-versa.

Multi-contributor Funding Schemes

Australian Proposed Plan. Utilities contribute an amount equivalent to the costs eliminated by placing facilities underground (tree trimming, restoration, lost sales). National, state and local governments make contributions on behalf of the wider public in proportion to the quantifiable externality benefits to the wider public (reduced vehicle/pole accidents, reduced electrocutions, reduced losses to business due to outages, and any beneficial indirect effects on the economy such as growth in employment or gross domestic product), or where a government considers it desirable to contribute towards improved visual amenity.

The gap (after avoided costs and government contributions as stated are contributed) is then funded through surcharges on the rates of property owners in undergrounding areas, who will receive most or all of the remaining benefits. This is a local-area decision-making option, where residents in local areas decide for themselves whether they value the urban amenity benefits sufficiently to proceed with undergrounding.

Charleston/SCE&G Plan.[101] The City Council of Charleston, South Carolina, will by ordinance designate an area as an underground utility district upon written petitions and approval of certain conditions by two-thirds of the property owners in the proposed district. Customers in a designated underground utility district must pay an annual underground utility fee to the City of Charleston until 15 percent of the total relocation cost has been collected. The underground utility fee is based on a combination of the assessed value and the frontal footage of all real developable property located within the district. Customers must also pay individual connection costs.

Another 35 percent of the cost would be paid by the City of Charleston out of an account funded from a portion of the utility franchise fees. The franchise agreement with the City of Charleston was negotiated in 1996; the Crescent neighborhood was designated in 2004 as the first underground utility district in Charleston. The remaining 50 percent of the project cost reportedly would be paid by the utility, South Carolina Electric & Gas, from electric rates approved by the Public Service Commission.

Boulder Program. The Undergrounding Cost Share Program ("UCSP") assists City of Boulder property owners with the undergrounding of existing overhead lines adjacent to their property through the use of the Xcel Energy Undergrounding Credit. As part of the city's franchise agreement, Xcel Energy earmarks one percent of the preceding year's revenues from accounts within the city for relocating distribution lines to underground or reconfiguring electric distribution or transmission lines in streets and other public places. One-fourth of this amount, or approximately $150,000, is set aside on a noncumulative basis for individual or business UCSP projects; however, the

[101] Information based on telephone conversations with A. Randy Watts, Chief, Electric Utilities Department, South Carolina Public Service Commission (803-896-5137) and Dan Kassis, SCE&G (843-576-8940). Also see Charleston Municipal Code, Article VIII, Section 30-172.

maximum contribution from the Undergrounding Credit is $50,000 per project, which ensures that multiple projects can be funded each year.

The Undergrounding Cost Share Program provides up to $50,000 in matching funds to facilitate individual undergrounding projects. Program participants pay 50 percent of the estimated Xcel and Qwest costs up to $100,000, and 100 percent of estimated Xcel and Qwest costs over $100,000, as well as any other costs associated with the project such as work by private electricians. Since 1995, 18 undergrounding projects (ranging from one city block to four city blocks in length) have been completed. The city anticipates the program could take 45-50 years to complete. A detailed summary of the Boulder program is provided in Appendix H.

The California Plan. Beginning in 1967, the California Public Utilities Commission ("CPUC") required new electric service connections to be placed underground and funded a program to gradually convert existing overhead lines, including concomitant communication lines, to underground service.[102] Under CPUC Rule 20, undergrounding projects are financed by utility rate money,[103] combined rate funds and local tax proceeds, or private funds, depending on whether Rule 20A, Rule 20B, or Rule 20C provisions apply.

Under Rule 20A, all of California's investor-owned electric utility ratepayers – not just those in the location of a specific undergrounding project – bear most of the costs of the underground conversion projects. Rule 20A applies only to projects that are determined to produce a benefit to the general public. In addition the locality must have adopted an ordinance creating an underground district.

If an area is not eligible for Rule 20A, Rule 20B allows rate funds to subsidize an undergrounding project in an amount equal to the cost of an equivalent overhead electric system (typically 20 percent of the total undergrounding project) plus the cost of removing the existing overhead system (5-20 percent of the total cost).[104] The remaining cost is funded by local governments or through neighborhood special assessment districts. Suitable municipal legislation must be in effect and all property owners must agree to certain conditions. Rule 20C enables property owners to pay for undergrounding electric lines and equipment for other applications. A detailed explanation of Pacific Gas and Electric Company's Rule 20 electric undergrounding program and its Rule 20 tariff are provided in Appendix I.

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[102] Energy Division Resolution E-3767, California PUC, June 27, 2002.

[103] The investor owned utilities are required to allocate 2% of gross revenues toward Rule 20 conversion projects. After projects are completed, the preauthorized capital expenditures are placed in rate base. Telephone communication with Brian Schumacher, Supervisor, Engineering Section, CPUC, 12/08/04.

[104] "Undergrounding Electric Lines and Equipment," Southern California Edison, 2000, http://www.sce.com/sc3/001_cust_care/001m_Undergrounding.htm, (15 June 2004).

SUMMARY, CONCLUSIONS AND RECOMMENDATIONS

House Joint Resolution No. 153 of the 2004 Regular Session of the Virginia General Assembly requested the State Corporation Commission to study the feasibility, costs and funding options relative to the placement of currently existing overhead utility distribution lines, and any new distribution lines, underground. The primary advantages of underground circuits are improved aesthetics, improved reliability, reduced tree trimming costs, and elimination of vehicle accidents with utility poles. However, the relocation of currently existing overhead lines would require tremendous investment and result in significant disruptions. In addition, a major relocation initiative could take decades to complete and encounter complications regarding underground damage prevention[105] and attainment of new easements.[106]

Based on the Staff's research and analysis and input from interested parties, the wholesale relocation of the currently existing overhead utility distribution lines and placement of all new utility distribution lines underground is probably not reasonable. The impacts from such efforts on state and local governments or utilities, and ultimately consumers, would be significant. The direct costs alone to relocate the currently existing distribution facilities underground were estimated by the electric utilities and telecommunications providers to be over $90 billion. The resultant impact on consumers would be significant, even if the costs were equally distributed, including among those customers that already have underground service.

The potential economic benefits, both to the utilities and to the economy, resulting from the elimination of tree trimming maintenance, vehicle accidents, post storm restoration and lost sales do not appear to be sufficient to offset the initial construction costs associated with a comprehensive program to relocate the currently existing overhead utility distribution lines to underground. The placement of all new distribution lines underground, though not as costly, also does not appear to be cost effective. Limited surveys of the public suggest that consumers might not be willing to pay the costs associated with a comprehensive undergrounding initiative. Other recent studies support these conclusions. In order to fully justify a comprehensive undergrounding initiative, consumers would need to place a sufficiently high valuation on non-economic benefits including, primarily, aesthetics and the avoidance of the irritation and hardships associated with blackouts following major storms.

A consensus of the interested parties[107] to this study did not support a comprehensive statewide relocation initiative, and believes that decisions relative to the placement of lines underground can be implemented most efficiently at the local level. Each locality should judge each individual project on its own merits and based on local citizens values and willingness to pay. Their authority notwithstanding, it appears localities would be in the best position to determine the most appropriate funding of such projects, facilitate coordination among the participating utilities, and classify projects in a

[105] Including potential conflicts associated with other existing underground utilities and dig-ins.
[106] Could involve significant time, negotiations with property owners and potential legal proceedings.
[107] "Interested parties" refers to those participants attending the kickoff meeting. Other members of the public (residential consumers) who responded to the SCC's website overwhelmingly favored undergrounding but generally were not willing to pay enough to fully fund it.

way that affords favorable tax and tariff treatment. All of Virginia's regulated electric utilities and telecommunications providers have policies and/or tariffs that govern the recovery of costs associated with the placement of underground lines in new developments as well as the conversion of currently existing overhead distribution facilities to underground

Presently, there appears to be language in the Code of Virginia that enables localities to require the undergrounding of *new* facilities. There does not appear to be any explicit authority in the Code enabling localities to require the undergrounding of existing facilities; however, there is the possibility that language in the Code could be so broadly construed to provide some authority for localities to establish service districts within which existing facilities must be undergrounded. It is less certain that localities have the authority to impose taxes or assessments upon the owners of property that abut undergrounded facilities.

APPENDIX A: RESOLUTION

HOUSE JOINT RESOLUTION NO. 153

Requesting the State Corporation Commission to study the placement of utility lines underground. Report.

Agreed to by the House of Delegates, March 10, 2004
Agreed to by the Senate, March 9, 2004

WHEREAS, the existence of overhead utility distribution lines has caused hardship in the past due to utility disruptions in urban areas in the Commonwealth during severe weather conditions, including hardship occurring during the recent hurricane; and

WHEREAS, placing underground the currently existing overhead utility distribution lines and any new utility distribution lines would reduce the number of weather-related utility disruptions; and

WHEREAS, placing underground the currently existing overhead utility distribution lines and any new utility distribution lines may reduce utility line maintenance costs; and

WHEREAS, placing underground the currently existing overhead utility distribution lines and any new utility distribution lines would minimize the visual pollution in the Commonwealth; now, therefore, be it

RESOLVED by the House of Delegates, the Senate concurring, That the State Corporation Commission be requested to study the placement of utility lines underground. The State Corporation Commission shall solicit the participation of interested parties in conducting a study of the feasibility of placing underground the currently existing overhead utility distribution lines and any new distribution lines, the costs that would be incurred, and the options for funding such underground placement.

The State Corporation Commission shall submit to the Division of Legislative Automated Systems an executive summary and report of its progress in meeting the directives of this resolution no later than the first day of the 2005 Regular Session of the General Assembly. The executive summary and report shall be submitted as provided in the procedures of the Division of Legislative Automated Systems for the processing of legislative documents and reports and shall be posted on the General Assembly's website.

APPENDIX B: PUBLIC COMMENTS

SUMMARY OF COMMENTS FROM MEMBERS OF THE PUBLIC

Residential Consumers

As mentioned in the report, the Staff received comments from approximately 115 residential consumers. The primary reasons given by consumers for placing distribution facilities underground were to improve aesthetics and reliability. Other potential benefits mentioned were improved safety, increased property values, creation of jobs, reduced accidents, reduced terrorist targets, and reduced impact on wildlife, trees and the environment. Others noted the potential benefit to the economy.

A number of different and conflicting recommendations were made with respect to the criteria to use to determine whether certain overhead lines would be eligible for being relocated underground; and there was no consensus. Different respondents suggested that priority should be given to hotels, water treatment facilities, municipal buildings, hospitals, food suppliers, residential areas, urban areas, tourist/historic/cultural/scenic areas, areas along major state highways, areas undergoing redevelopment, areas with the highest population density, areas with the lowest population density, and areas with the least reliable service. One respondent suggested that rural areas be assigned the lowest priority. Other respondents suggested that the SCC or a new governing board or local governments should administer the program and decide which circuits should be placed underground.

Several comments were received regarding potential funding options. One respondent suggested the effort should be accomplished via a competitive bid process to minimize costs. Another suggested that tax incentives should be created to encourage utilities. Many of the comments relative to funding suggested that the accrued annual savings resulting from reduced O&M and post-storm restoration efforts should more than offset the initial costs. Some of the respondents recommended various combinations of the individual funding options which are listed below.

- State budget for infrastructure improvements
- State or local government imposed surcharge
- Locality funding
- Legislate pro rata share provisions allowing localities to assess local developers
- Utility general rate increase
- Utility surcharge on bills of customers who convert to underground
- One-time customer payment
- Utility shareholders
- Property tax increase

- State government matching funds
- Accrued funds from fines established for outages or substandard reliability
- Federal funding

Local Governments and Civic Associations

This subsection provides a summary of the comments received from the Madison Manor Civic Association (Arlington County), Great Falls Citizen Association, Arlington County Board, Colonial Heights City Council, Danville City Manager, Hampton Roads Planning District Commission, New Kent County Department of Community Development, City of Norfolk Department of Public Works, Norfolk Redevelopment and Housing Authority, City of Roanoke Department of Public Works, and the Staunton City Manager.

The following is a summary of the suggested potential benefits of placing overhead distribution facilities underground:

- Improved reliability
- Improved aesthetics
- Improved safety (electrical, traffic)
- Reduced restoration costs after storms
- Reduced impact on economy from major storms
- Reduced impact on shade trees
- Reduced cost of tree trimming maintenance
- Reduced sidewalk obstacles
- Promotes more desirable communities
- Increases property values
- Reduced sidewalk repairs from pole replacement

Disadvantages listed included costs of installation, the duration (decades) and disruption of the work, cost to consumer to convert customer-owned facilities to accept underground service, the potential for increased conflicts during excavations, longer repair times and duration of outages, susceptibility to flooding, additional costs for new street lighting poles and fixtures,

Recommendations for priority areas included municipal pumping stations and facilities that directly affect public health, major arteries, gateways to neighborhoods and high visibility streets serving a large number of customers, urban areas, tourism/scenic/historic areas, high density circuits with poor reliability, ugly circuits, areas budgeted for upgrade of existing overhead facilities, areas where consumers are willing to pay the cost, and redevelopment areas.

The recommended funding options included the following:

- Small increase in utility bills to accommodate a 20-year plan.
- Shared funding by utilities, developers and consumers.
- Fund one-third of marginal cost via a temporary surcharge across all customer bills for a defined period (similar to Dominion's fuel surcharge). Fund remaining two-thirds by utilities (out of net income and savings that accrue from improved reliability and lower maintenance costs).
- State Department of Transportation/Transportation Enhancement Funds under categories of landscaping/scenic beautification.
- State community improvement grants or other competitive grant programs.
- Create special assessment district for neighborhood projects.
- Establish an "underground fund" with a percentage of gross revenues to underground one or two percent of high priority facilities per year.
- The utility companies should work with localities to explore opportunities available during various stages of design to minimize right-of-way and utility relocation costs. Utility companies should consider possible design of underground alternatives that will avoid additional cost to localities and cost cure items.

The following public policy considerations were also suggested:

(1) Local ordinance should encourage or require the placement of new underground utility facilities and should establish the conversion of existing overhead utilities to underground where local need is greatest and timing can be coordinated to redirect planned utility upgrade budgets to the conversion of facilities from overhead to underground. Because widespread conversion of utilities from overhead to underground is cost prohibitive, local government is better prepared to coordinate targets of opportunity to cost effectively focus on achieving long term objectives through meeting short term goals.

(2) State law should mandate the use of underground facilities. Local authority does not exist to require removal and replacement of existing overhead facilities except where the facilities have to be moved as part of the development process. Localities should be given an option to be more restrictive with respect to new utility placements. Establish a deadline (for example, 10 years) by which all utilities (including electrical wiring below 50kV, telephone and CATV wires, cables or fiber) will be placed underground.

(3) State law should mandate the use of underground facilities and local ordinance should implement the process, in order that each locality can govern the schedule and criteria of undergrounding in accordance with development trends. Individual cities could include undergrounding provisions within franchise negotiations with private utility companies.

(4) Cities and counties should be treated equally in the Virginia Code with regard to developing cost sharing requirements with utility companies.

(5) Utility companies should be required to provide explicit documentation of cost estimates and charges related to relocating utility lines and such work should be competitively bid to the extent possible.

(6) State law should allow utility companies, upon concurrence from the local governments, to incorporate into their rates an amount for "utility relocation" accounts in the range of 1% to 2% of gross revenues obtained from all accounts in that particular community. Such funds should be specifically accounted for and used for utility undergrounding to replace above ground utilities based on a locally developed long-range plan.

(7) Criteria and guidelines regarding standards by which utility companies respond to local government requests for utility relocations in a timely manner should be developed.

(8) The State, by imposing regulations and quality assurance standards on the utility companies, should provide for underground infrastructure in redeveloping areas to ensure equity between fully built and undeveloped areas regardless of the type of development or specific power requirement in order to promoted sustainable neighborhoods.

<u>Sierra Club Virginia Chapter</u>

The Energy Issues Chair of the Sierra Club Virginia Chapter ("Sierra Club") provided a lengthy discussion on the underground placement of utility distribution lines. In summary, the Sierra Club noted that placing distribution lines underground would permit greater tree use and improve reliability. The Sierra Club also surmised that many citizens would be willing to pay the extra costs if they understood the trade-offs, if those costs were equally distributed and spread over the lifetime of the system, and if they were given a choice.

The Sierra Club thought the fairest funding option might be an additional unit charge for electricity use [for example, cents per kWh] for all customers within the area affected by underground placement to recover incremental costs net of savings from reduced maintenance costs. However, the Sierra Club's recommendation is contingent upon an assumption that residents of new subdivisions (as opposed to the entire customer base, including those with overhead service) pay the extra cost differential between overhead and underground service. The Sierra Club recommended against a special tax assessment instrument because it would not correlate with electricity use.

With respect to legislative options, the Sierra Club suggested that state law should authorize localities to determine whether to place utility distribution facilities underground. The Sierra Club also recommended that state law prescribe appropriate, democratic procedures for reaching a decision that assures that the views of all property owners are considered and weighed in the process (for example, local government supervision of a process implemented by homeowners' associations).

Complete Responses

The full responses from the Sierra Club, the Madison Manor Civic Association, the Great Falls Citizens Association, and the various government entities identified can be obtained by contacting W.T. Lough, Special Projects Engineer, at 804-371-9590.

APPENDIX C: RESPONSES TO GENERIC QUESTIONS

HJR 153 FEASIBILITY STUDY

RESPONSES TO GENERIC QUESTIONS SUBMITTED TO INTERESTED PARTIES

The following represents the Staff's compilation of responses submitted by Arlington County, City of Fairfax, Home Builders Association of Virginia, The Virginia Cable Telecommunications Association, Shenandoah Telephone Company, Sprint, Verizon, VMD Association of Electric Cooperatives, Allegheny Power, Appalachian Power Company, Conectiv Power Delivery, Virginia Power, and Old Dominion Power Company.

1. Please identify the major issues/questions that should be addressed by the HJR153 feasibility study.

ISSUES DEEMED FUNDAMENTAL TO COMPLETING THE STUDY:

a) Definition of "utility" envisioned by HJR 153 (electric, telecom & cable assumed)
b) Definition of "distribution" envisioned by HJR 153 (all categories, incl. service entrances; transmission lines excluded)
c) Geographic scope of study (entire state, not just "hurricane susceptible" areas)
d) Identification and relative ranking of perceived reasons/benefits for undergrounding
e) Identification of alternatives to undergrounding that might improve reliability/aesthetics
f) Analysis of the operational advantages/challenges associated with underground circuits
g) Analysis of installation and O&M advantages/challenges with underground circuits
h) Cost impacts of expanding underground facilities relative to overhead facilities
i) Identification of funding options (state/local surcharge, rates, case-by-case funded, customer)
j) Identification of obstacles to certain funding options
k) Impacts of competition on funding options
l) Identification of issues related to Contribution-in Aid of Construction (gross-up TERF tax)
m) Analysis of initial capital/construction costs, annual O&M costs, life cycle costs
n) Relative reliability and life expectancy of overhead vs. underground lines
o) Impact on joint use customers
p) Method of retiring existing overhead facilities
q) Environmental impacts of widespread conversion
r) Labor and material impacts of widespread conversion

ISSUES TO BE DEFERRED (resolved post-study as necessary):

s) Determination as to whether undergrounding, if feasible, is in the public interest based on the citizens perceived weighting of costs and benefits.
t) Definition of "urban" and/or "rural" (if a determination is made generally that undergrounding is only feasible in urban areas, then a specific definition may be necessary)
u) Determination of the preferred funding option

v) Determination of cost allocation
w) Actions/policies to be pursued regarding contributions-in aid of construction
x) Establishment of a schedule for completing the conversion (compatible with resources)
y) Development of a prioritization process (criteria, annual miles, annual expenditures, hearing process)
z) Determination of the role of utilities in improving the visual environment in the state
aa) Determine who should make the decisions that affect the safety and quality of life for citizens

2. Please describe the potential benefits to the public and utility companies associated with the undergrounding of overhead distribution lines.

    Improved reliability during severe weather conditions, improved day-to-day reliability, enhanced aesthetics, reduced restoration costs, reduced tree trimming costs, reduced motor vehicle pole accidents, reduced electrocutions from crane and mast contacts, reduced hazard from downed lines, reduced hazard to utility workers (falls, work zone vehicle accidents), reduced accessibility to the public, smaller rights-of-way, permits closer proximity between electric and communications infrastructure, lowers delivery line losses as a result of large and more compact underground cable constructions, reduced hostility between the utility and homeowner over trees, allows natural healthy tree growth, improved economic development opportunities for local governments, increased property values, creates pedestrian friendly walkway.

3. Please describe the potential negative impacts on the public and utility companies associated with the undergrounding of overhead distribution lines.

    Higher capital costs for utilities, increased ongoing costs/rates/taxes associated with the conversion, high initial cost to customer for provision of underground service lateral and service entrance modifications, increased maintenance costs, increased modification/expansion/replacement costs, reduced life expectancy of lines and equipment, increased susceptibility to dig-ins, increased Miss Utility costs, longer failure analysis, increased length of outage repair, outages that involve more customers (due to fewer reclosers and switches), disruptions from maintenance might be greater, initial construction disruption, damage to tree roots, need for private right-of-way agreements, wider easements might be needed to accommodate parallel corridors for subsequent replacements or new occupants, rewiring of service entrance equipment, reduction of developable area on some lots, telecom customers will be incented to avoid increased costs by switching to wireless services, dilution of workforce normally used to install new services, susceptiblility to flooding damage, high voltage safety concerns with pad mounted equipment (vandalism, accidents), aesthetic concerns regarding the relocation of backyard aerial service to street side *underground service, less flexibility with respect to upgrading or reconfiguring circuits, requires replacement of street lights normally attached to poles, increased installation cost of advanced cable services due to the loss of "overlashing" capability.*

4. Please describe in detail the potential obstacles associated with the implementation of a program to relocate overhead distribution lines to underground (for example, statutory, regulatory, technological, economic, safety, and physical obstacles).

   (a) 29% Federal TERF gross-up tax for some IOUs
   (b) Need to obtain some new right-of-way agreements
   (c) Issues related to joint trenching and collocation
   (d) Communication cabling cannot be collocated with power equipment (electromagnetic interference, inability of labor force to work in close proximity to power which precludes communications utilities from sharing structure for conduit systems with power utilities)
   (e) Environmental impacts of open trenching
   (f) Relocation of lines may be challenged by gas and water companies
   (g) Physical constraints: existence of other underground utilities, space limitations, location of pad mounted equipment, terrain
   (h) Utility ambivalence: unprofitable, not viewed as a service enhancement
   (i) Labor and equipment shortages hinder timely completion
   (j) Citizen unwillingness to pay
   (k) Citizen aversion to pad mounted equipment on property
   (l) Litigation regarding new easements
   (m) Changes to state law granting specific authority
   (n) Deregulation/rate cap impact on recoverability of costs via rates
   (o) Cost prohibitive
   (p) Significant retirement of existing electrical plant and increase of new plant to the electrical delivery system
   (q) Inability to recover undepreciated aerial assets (stranded investments)

5. Please describe the process for identifying and securing right-of-way easements for the relocation of existing overhead distribution lines to underground. What property rights issues would be raised as a result?

   Many of the respondents are confident that existing powers of eminent domain appear to be sufficient for securing easements and that most older overhead utility easements include the ground below existing aerial lines.

   However, all overhead right-of-way would have to be identified and a legal review would be required on a case-by-case basis to determine if the easement contains the right to locate underground facilities.

If the easement does not provide these rights, each land owner would need to be contacted and the right-of-way agreement modified to include this capability prior to undergrounding facilities.

Other more specific activities that complicate the process, such as designing the project, engaging in meetings with landowners and recording easements at the court house, were provided by some respondents but are not listed here for purposes of brevity; however, such responses will provide valuable information in terms of understanding the details of the process.

Other potential issues identified:

- *Need to amend or acquire new easements for private/public property*
- *Damage claims from property owners*
- *Establishing route for new easements*
- *Possible need for environmental assessment*
- *Need a revised streamlined and standard process for designing and acquiring easements so that the design and right-of-way acquisition activities can occur simultaneously.*
- *Utilities are not motivated to aggressively pursue rights-of-way for undergrounding, so local government staff must secure most underground r-o-w for a project to proceed to construction.*

6. In order of importance, list the criteria that should be considered to determine whether the implementation of a program to relocate overhead distribution lines to underground is desirable.

	No. of Responses
Life cycle cost to the utilities	*10*
System Reliability	*8*
Availability of a workable funding mechanism	*5*
Public Input	*3*
Safety/Accidents	*3*
Annual cost to the ratepayer or taxpayer	*2*
Service Restoration	*2*
Technical Feasibilty	*2*
Aesthetics	*2*
Private property right-of-way	*2*
Legal issues	*1*
Duration of the construction process	*1*
Public Policy	*1*
Out-of-pocket cost of conversion to customers	*1*
Operational advantages and disadvantages	*1*
Disruptions from construction activities	*1*
Impacts on existing service and provision of new service	*1*

Impact on competitive advantage	*1*
Percentage of system converted to underground	*1*
Impacts on non-electric utilities	*1*
Future technologies	*1*

7. In order of preference, describe the potential options for funding the relocation of overhead distribution lines to underground and explain the basis of your recommendation.

<u>Listed In No Particular Order of Preference</u>

The cost should be shared by ratepayers, taxpayers, and utility investors. Ratepayers should fund that portion of the costs related to reliability, taxpayers should fund that portion of the costs related to aesthetics, and the utility investor should fund that portion of the cost attributable to incremental improvement in plant asset value.

Because of the significant costs involved, such a program should be offered as an optional improvement funded by the customers receiving the benefits of conversion to underground, either by the locality's tax structure or a surcharge on the customers' utility bills in the locality.

Public funding is necessary in order to mitigate the competitive advantage that would otherwise be afforded to wireless or VoIP providers as result of other funding options.

Ratepayers by means of an automatic rate adjustment, possibly in the form of a rate added.

Adjust capped rates for the recovery of the incremental costs incurred for T&D system reliability improvements (undergrounding), in accordance with state law, and levy a surcharge on all customers of the utililty. This might be considered equitable because all ratepayers would avoid the cost of restoration following catastrophic storms. This might not be considered equitable because some of the burden would fall on customers that don't directly benefit from the undergrounding.

The government entity (state or local) requiring undergrounding should pay the cost through direct funding from current revenues without a tax increase.

The taxpayers of the government entity (state or local) requiring undergrounding should pay the cost from an increase in taxes if it can be justified on the basis of a "societal benefit."

Utilities' investors should fund the cost of undergrounding.

Specific options tried in the past include general funds, bond funds and developer contributions to remove the overhead lines. Tax Improvement District funding is another possible revenue source.

8. Should one or more pilot programs be conducted to determine more precisely the benefits, costs and obstacles associated with the implementation of a program to relocate overhead distribution lines to underground? If pilot programs should be conducted, how could and should the pilot programs be funded?

    Yes. (6 responses – home builders association, 2 telecom providers, 3 electric utilities) If the initial study determines that undergrounding is feasible, then pilot programs should be conducted in different geographies and on different types of infrastructure – perhaps in conjunction with a redevelopment project – to refine and confirm the costs and benefits. Pilots should be funded by grants to the utility, or by utility expenditures that can be passed through to ratepayers, or by local residents who agree to pay for the cost of undergrounding.

    No. (7 responses – 2 municipalities, cable industry, telecom provider, 2 electric utilities, electric co-op) Sufficient previous experience.

9. Considering the costs, benefits and obstacles associated with the implementation of an undergrounding program, should the General Assembly require utilities to place all or a portion of existing and/or new overhead distribution lines underground? Alternatively, should such decisions be left to local government? Please explain your answer.

    No. Neither the GA nor the local governments should require undergrounding of existing overhead distribution lines (5 responses – cable industry, 2 telecom providers, electric utility, electric co-op)

    Yes, the GA should require all new and existing developments to be placed underground, if costs are distributed among all citizens or ratepayers. (2 responses – home builders representative, municipality)

    Perhaps a portion of existing lines meeting a vulnerability test. (1 response – telecom provider)

    The GA should specifically empower municipalities to require undergrounding of new and/or existing facilities. (3 responses – 2 municipalities, electric utility)

    If the GA should specifically empower municipalities to require undergrounding of new and/or existing facilities, the GA should establish uniform standards for policy making. (1 response – electric utility)

The GA should empower municipalities to require undergrounding of new residential subdivisions only (1 response – electric utility)

The decision should be made by the customers who receive the benefits and ultimately will fund the costs. (1 response – electric utility)

10. What obstacles, if any, currently prevent a local government from enacting an ordinance establishing all or a part of the locality as an area in which: (a) existing overhead utility distribution lines must be relocated underground over some period of time; and/or (b) all new utility distribution lines must be located underground?

    State law does not specifically authorize local governments to require utilities to relocate existing utility lines underground. (4 responses – 2 municipalities, telecom provider, electric utility)

    Requiring relocation of existing utility lines would be at odds with Va. Code Section 56-234 that requires utilities to provide adequate service only. (1 response – telecom provider)

    A local ordinance requiring relocation of existing lines or the undergrounding of new lines without just compensation would violate the 5th and 14th Amendments to the Constitution that prohibit governmental entities taking private property for public use without just compensation. (1 response – telecom provider).

    State law does allow for new lines to be located underground in the case of construction of new developments, but at the expense of the developer. (2 responses – municipality, electric utility)

    Not sure (7 responses). Others identified economic costs and political fallout.

11. For the specific purpose of funding the undergrounding of existing overhead utility distribution lines, what obstacles, if any, currently prevent a local government from levying a special tax on the residents and businesses of an area within the locality in which the local government has enacted an ordinance requiring the undergrounding of utility distribution lines? Would such a special tax assessment require specific new authorization from the General Assembly?

    Current law allows for the formation of special taxing districts that have been interpreted to include placement of utilities underground. To avoid potential litigation, it would be helpful to have the law revised to specifically include the placement of utilities underground as an eligible expense. (2 responses)

Any special tax must be authorized by the GA (3 responses), but the GA should not authorize such a tax (1 response).

Not Sure (6 responses)

APPENDIX D: BASIS FOR ELECTRIC UTILITY CONVERSION COST ESTIMATES

VIRGINIA POWER

Unit conversion cost, mileage, number of services, total cost (assuming directional boring in conduit):

Heavy Commercial/ Urban Residential District	**Unit Conversion Cost ($/mile or $ per service)**	**Mileage (miles or # of services)**	**Total Cost ($)**
3Φ Bulk Feeder	$3.1 million per mile	1,743 miles	$5.4 billion
3Φ Tap	$3.1 million per mile	1,404 miles	$4.3 billion
1Φ Tap	$1.4 million per mile	3,707 miles	$5.0 billion
Residential Services	$4,269 per service	758,476 services	$3.2 billion

Suburban	**Unit Conversion Cost ($/mile or $/service)**	**Mileage (miles or # of services)**	**Total Cost ($)**
3Φ Bulk Feeder	$2.5 million per mile	2,336 miles	$6 billion
3Φ Tap	$2.0 million per mile	1,763 miles	$3.5 billion
1Φ Tap	$1.4 million per mile	7,107 miles	$9.6 billion
Residential Services	$4,269 per service	443,500 services	$1.9 billion

Rural	**Unit Conversion Cost ($/mile or $/service)**	**Mileage (miles or # of services)**	**Total Cost ($)**
3Φ Bulk Feeder	$2.7 million per mile	1,910 miles	$5.1 billion
3Φ Tap	$2.1 million per mile	2,483 miles	$5.3 billion
1Φ Tap	$1 million per mile	12,662 miles	$12.7 billion
Residential Services	$7,092 per service	335,470 services	$2.4 billion

Anticipated installation methods:

	Direct Bury w/ Cable Plow	Direct Bury w/ Trencher	Cable in Conduit w/ Trencher	Directional Boring w/ Guide Drill	Concrete Duct bank w/ Manholes	Hoe Ram, Rock Saw, Dynamite
Commercial	0 %	2 %	4 %	4 %	90 %	0 %
Urban	0 %	38 %	26 %	5 %	30 %	1 %
Suburban	0 %	53 %	20 %	5 %	20 %	2 %
Rural	4 %	60 %	18 %	4 %	10 %	4 %

Actual conversion case[108] cost breakdown:

- Materials – 34%
- Contractor labor & equipment – 29%
- General & administrative overhead – 21.5%
- Company labor – 8%
- Other – 7.5%

[108] Based on approximately 1 mile conversion of three-phase bulk feeder in urban Williamsburg. The conversion was completed for aesthetics and in association with a VDOT road widening project.

APPALACHIAN POWER COMPANY

Unit conversion cost, mileage, number of services, total cost:[109]

Heavy Commercial District	Unit Conversion Cost	Mileage	Total Cost
3Φ Bulk Feeder	$ 2.1 million per mile	417 miles	$ 0.86 billion
3Φ Tap	$ 1.3 million per mile	208 miles	$ 0.28 billion
1Φ Tap	$ 0.22 million per mile	2,263 miles	$ 0.49 billion
Residential Services	$ 0.19 million per mile	2,098 miles	$ 0.38 billion

Urban – Residential	Unit Conversion Cost	Mileage	Total Cost
3Φ Bulk Feeder	$ 1.3 million per mile	465 miles	$ 0.62 billion
3Φ Tap	$ 1.3 million per mile	233 miles	$ 0.31 billion
1Φ Tap	$ 0.16 million per mile	2,527 miles	$ 0.40 billion
Residential Services	$ 0.13 million per mile	2,342 miles	$ 0.30 billion

Suburban	Unit Conversion Cost	Mileage	Total Cost
3Φ Bulk Feeder	$ 1.3 million per mile	507 miles	$ 0.67 billion
3Φ Tap	$ 1.3 million per mile	254 miles	$ 0.34 billion
1Φ Tap	$ 0.16 million per mile	2,753 miles	$ 0.44 billion
Residential Services	$ 0.13 million per mile	2,552 miles	$ 0.33 billion

Rural	Unit Conversion Cost	Mileage	Total Cost
3Φ Bulk Feeder	$ 1.3 million per mile	1,820 miles	$ 2.4 billion
3Φ Tap	$ 0.57 million per mile	910 miles	$ 0.5 billion
1Φ Tap	$ 0.16 million per mile	9,881 miles	$ 1.6 billion
Residential Services	$ 0.13 million per mile	9,160 miles	$ 1.2 billion

Anticipated installation methods:

	Direct Bury w/ Cable Plow	Direct Bury w/ Trencher	Cable in Conduit w/ Trencher	Directional Boring w/ Guide Drill	Concrete Duct bank w/ Trench	Cable Tray (attached to buildings)	Concrete Duct (above ground)
Commercial	0 %	0 %	25 %	15 %	60 %	0 %	0 %
Urban	0 %	0 %	12 %	30 %	50 %	3 %	5 %
Suburban	0 %	74 %	10 %	10 %	5 %	1 %	0 %
Rural	0 %	90 %	0 %	5 %	1 %	1 %	0 %

Estimated cost breakdowns:

- Materials – 40 %
- Labor – 36 %
- Aerial facilities removal (6.8%) and salvage credit (0.8%) – 6 %
- Administrative & general and construction overheads not included in cost estimates – 15.3 %
- Other – design, right-of-way acquisition, vehicles – 3 %

[109] APCO costs estimates do not include underground feeder sectionalizing and voltage correction costs which would substantially increase the costs. Also, estimate of underground lines is under estimated because accessibility and rolling terrain issues have not been considered.

APPENDIX E: ECONOMIC COST OF OUTAGES TO RESIDENTIAL CONSUMERS

ANALYSIS OF THE ECONOMIC COST OF OUTAGES TO RESIDENTIAL CONSUMERS

The U.S. Department of Energy (Office of Electric Transmission and Distribution, Energy Storage Program) recently funded a study by Lawrence Berkeley National Laboratory ("LBNL")[110] to develop better estimates of the economic value of electricity reliability.[111] According to the LBNL study, a clear understanding of the monetary value that customers place on reliability and the factors that give rise to higher and lower values is an essential tool in determining investment in the grid. The Staff attempted to use the conclusions from the LBNL study regarding economic value of reliability in order to estimate the impact of outages on residential customers.

Based on the LBNL study, the outage cost experienced by an "average" residential customer in the Southeast could be estimated very roughly to be as much as $7 per 4-hour outage event.[112] These figures can be used to estimate the impact of electric power outages on Virginia's economy. In a given year, Virginia's 2.8 million residential customers could experience 11 million hours of outage time.[113] Assuming these hypothetical numbers, the total annual cost to Virginia's economy from lost load can then be calculated as approximately $20 million for residential customers, in the hypothetical typical year.[114] Perhaps as much as 80% of these economic costs could be attributable to outages resulting from interruptions to overhead distribution facilities statewide.[115]

According to the LBNL, the models used in the study cannot be used to estimate damages for individual customers. In commenting on the LBNL study, a senior research specialist with the National Regulatory Research Institute ("NRRI") noted that because there is no "average" outage and no "average" customer one needs to analyze the marginal costs of specific individual customers or subgroups of customers.[116] The Staff agrees that further analysis would be needed to determine whether improved reliability, as a result of converting overhead distribution facilities to underground, might be cost effective at the local level or for a specific circuit.

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[110] L. Lawton, et al. (Population Research Systems, LLC) and J. Eto (LBNL), *A Framework and Review of Customer Outage Costs: Integration and Analysis of Electric Utility Outage Cost Surveys*, November 2003.

[111] Ibid. Twenty-four studies, conducted by eight electric utilities between 1989 and 2002 representing residential and commercial/industrial (small, medium, and large) customer groups, were chosen for analysis. All variables were standardized to a consistent metric and dollar amounts were adjusted to the 2002 CPI; the data were then incorporated into a meta-database.

[112] Ibid. This statement is based on a rough extrapolation of average costs by duration and region provided in two tables: Table 5-2. Average Outage Costs by Duration and Table 5-3. Average Outage Costs for Key Variables (WTP and WTA).

[113] Based on hypothetical statewide average interruption duration of 4 hours per year per customer.

[114] 2.8 million 4-hr events x $7 per 4-hr event = $20 million.

[115] In 2002, approximately 79 percent of the total customer hours of outages were attributable to interruptions on overhead distribution facilities on Virginia Power's system. The remaining 21 percent were attributable to interruptions related to bulk power, failure of underground facilities, dig-ins, and company-initiated activities. Distribution facilities placed underground would still be subject to outages from dig-ins and failure of underground equipment.

[116] Robert E. Burns, "Electric Reliability: How Much, By What Means, At What Cost?" 24th Annual North American Conference of the USAEE/IAEE.

NRRI, in development of its FY 2005 research agenda, conceptualized a research project and survey to more accurately examine the value of reliability. As NRRI conceived the project, the focus would be to examine what value users place on reliability. With this information, states would be able to make informed decisions about whether or not measures such as burying distribution lines actually pass a value/benefit test. Currently, this "value of reliability" project is on NRRI's list of potential projects pending a specific client or state agency in search of such a project. NRRI also indicated it would be capable of conducting a study for a particular service area via a contract from a local governing body.[117]

[117] Emails to W.T. Lough from R. Scott Potter, Senior Research Specialist, NRRI, Ohio State University, 614-292-9446, potter.138@osu.edu , November 2 and 3, 2004.

APPENDIX F: WILLINGNESS TO PAY

CONSUMERS' WILLINGNESS TO PAY

The Staff attempted informally to obtain a preliminary anecdotal understanding of Virginia's residential consumers' willingness to pay ("WTP") for undergrounding distribution facilities by surveying two distinct groups of individuals: the interested parties who attended the Commission's August 16, 2004, kickoff meeting for the feasibility study, and those members of the public who both responded to the Commission's invitation to comment and provided an email address. A summary of these results is provided in the following table.

Residential Consumers WTP for Undergrounding Utilities	Average Monthly WTP (Statewide Conversion) ($ per month)	Average Monthly WTP (Partial Conversion) ($ per month)	Average Initial one-time fee [b] ($)
Interested Members of the Public w/ Overhead Service	24	17	392
Kickoff Meeting Participants w/ Overhead Service	9 [a]	not asked	400
Kickoff Meeting Participants w/ Underground Service	6 [a]	not asked	not applicable

Notes:

(a) Kickoff meeting participants were asked to provide WTP figures on an annual basis which were then converted to a monthly basis for consistency in the table.

(b) The average initial one-time fee would be for replacement of the customer's individual aerial service wire from the pole to the residence with an underground cable.

In each case, participants were asked to estimate their willingness to pay a monthly or an annual fee for relocating overhead distribution facilities to underground, as well as a one-time fee for installation of an underground service lateral between the poles and their residences. Participants were also asked to provide personal information that could impact their willingness to pay, including (a) whether they had underground or overhead service, (b) whether or not they owned or had made a decision to purchase a backup generator, (c) their outage experience with Hurricane Isabel (the most recent and widespread catastrophic storm to have impacted the state at the time of the survey), (d) their perception of their general level of reliability, and (e) their perception of their household income. In addition, participants were in some cases provided additional information to educate them about the various reported costs and benefits associated with undergrounding. Copies of the surveys are provided at the end of this Appendix.

The WTP results obtained by the Staff's surveys are indicative only and do not represent a scientific analysis of consumers statewide. Additional research and analysis, including both residential and commercial customers, is needed to provide more robust estimates of Virginia consumers' WTP for undergrounding. The Staff also reviewed the results of a survey conducted in England, Scotland and Wales. Summaries of the Staff's research and analysis are provided in the paragraphs below.

Kickoff Meeting Participants. The interested parties that attended the Commission's kickoff meeting on August 16, 2004, were issued a survey that included questions regarding their willingness-to-pay to relocate overhead distribution lines to underground. Of the 43 attendees who provided a valid response to the Staff's survey, 12 had overhead service and 31 had primarily underground service. The 12 respondents who had overhead service expressed WTPs to underground the entire state that ranged from $0 to $500 per year, with an average of $108 per year ($9 per month). In addition to the annual fee, the respondents indicated an average WTP of approximately $400 (as a one-time fee) to underground their individual service laterals from the poles to their residences. The 31 respondents who had underground service expressed WTPs to underground the entire state that also ranged from $0 to $500 per year, but with a lower average of $74 per year ($6.16 per month). Approximately half of each group expressed an unwillingness to pay anything.

Members of the Public. As mentioned elsewhere, as a result of its invitation to the public to comment on the feasibility study, the Commission received an initial reply from approximately 115 individual consumers. The Staff attempted to explore their willingness-to-pay ("WTP") for undergrounding by submitting a survey electronically to the approximately 74 consumers who also included an email address in their comments. Of the 33 (43.2 %) consumers who provided a valid response to the Staff's electronic survey, 22 had overhead service (four of whom also had an underground lateral only from the pole to the residence) and 11 had primarily underground service.

The 22 respondents who had overhead service[118] expressed WTPs to underground the entire state that ranged from $0 to $100 per month.[119] The average and median values of WTP for these 22 respondents were $24 per month and $13.50 per month, respectively. When asked about their WTP to underground not the entire state but only the least reliable and most unattractive circuits in the system (with no guarantee that their own circuits would be placed underground), the number of persons that were unwilling to pay anything increased from one to six, and the average WTP dropped from $24 per month to approximately $17 per month. In addition to the monthly fee, the respondents indicated an average WTP of approximately $392 in the form of a one-time fee to underground their individual service laterals from the poles to their residences (excluding the four respondents who already had an underground service lateral from the pole to the residence).

Among these few respondents, the Staff found no obvious correlation between WTP and the individual's perceived income level, service reliability, or Hurricane Isabel related experience. In fact in some cases, the individual's WTP seemed counterintuitive with respect to these variables. For example, one individual who perceives that he has excellent reliability (and also owns a backup generator and experienced only 1 day out as a result of Hurricane Isabel) and average income expressed a WTP of $100 per month. At the other extreme, another individual who perceives that he has poor reliability (and experienced an 8-day outage with Hurricane Isabel and does not own a generator) and above average income expressed a WTP of only $10 per month. Other variables besides reliability and income that might influence an individual's WTP could be the value

[118] These 22 respondents live in Arlington (10), Richmond (7), Charlottesville (3), Chester (1), and D.C. (1).

[119] The 11 respondents who already have underground service expressed WTPs that ranged from $0 to $80 per month.

placed on aesthetics, the amount of discretionary income available, and feelings about how costs for undergrounding should be funded. Any entity or locality desiring to use WTP to influence policy would need to conduct a comprehensive and in-depth scientific study of consumers living in the locality.

England, Scotland and Wales. In a 2003 survey of customer attitudes in England, Scotland and Wales prepared by Accent Marketing & Research of London[120] for Ofgem,[121] respondents were asked if they would be prepared to pay extra for distribution companies to put five percent of their overhead lines underground, thereby helping to reduce the number of power outages and the visual impacts of overhead lines but increasing the time taken to repair faults. Forty percent said they would pay extra but 54 percent would not. Willingness to pay was highest among 16-29 year olds and business professionals. The average WTP – among those willing to pay – was 2.7 pounds per month or 3% on top of their monthly bill (excluding outliers). Including customers who are not willing to pay would dilute this average. Three percent of the average monthly residential bill in Virginia during 2003 was approximately $2.74 per month.[122]

According to the survey, 75 percent of customers interviewed would like to see more cables laid underground in their own area, this figure rising to 80 percent in rural areas. The main reasons for wanting cables laid underground were aesthetics and safety. The main reasons given by the 25 percent not wanting cables laid underground in their local areas were that they were not bothered by aerial facilities, didn't want the ground dug up, and were told that it would be more difficult for the utility to locate and repair faults.

[120] *Expectations of Electricity DNOs & WTP for Improvements in Service*, Stage 1 Quantitative Research Findings, Final Report: September 2003. London. DNO is an acronym for Distribution Network Operator.
[121] Ofgem was formed in 1999 with the principal objective of protecting the interests of gas and electricity consumers in England, Scotland and Wales
[122] Based on 39,065,767 MWh sold to Virginia's 2,792,662 residential customers of IOUs and Co-ops at an average price of 7.83 cents per kWh.

Kickoff Meeting Participants

Undergrounding: Desirabilty Criteria & Willingness-To-Pay Survey

Please answer the following questions using your own personal perspectives.
Assuming that the relocation to underground of at least a portion of the existing aerial distribution system is feasible, please rank the five most important criteria that should be considered to determine whether the relocation of overhead distribution lines to underground is desirable. (Rank only five of the criteria, where a rank of "1" is most important. You may rank more than one criterion at the same level.)

(___) Level of cost in the form of taxes and/or utility rates (Based on capital and O&M costs less savings in right-of-way maintenance and outage restoration)
(___) Reliability during catastrophic storms
(___) Day-to-day reliability
(___) Property value (and tax assessment)
(___) Safety (electrical, physical and vehicular hazards)
(___) Aesthetics
(___) Tree impacts (overhead trimming damage, underground trenching damage)
(___) Other, if necessary____
(See responses to generic questions 2, 3, and 6 to refresh your memory)
(___) Other, if necessary____

Please complete the following questions:

1. Existing service at your residence: overhead/underground
2. Do you now own or have you made a decision to purchase a generator? Yes/no
3. How many days were you without power as a result of Hurricane Isabel?__________
4. How much would you be willing to pay for the relocation of overhead distribution lines to underground in the form of taxes or utility rates on an annual basis? (circle one)
   $0 $50 $100 $200 $500 $1000 $1500 $2000 $2500 $3000 $3500 $4000
5. If you have overhead service, how much would you be willing to pay initially out-of-pocket in order to convert the overhead service drop attached to your residence to an underground lateral cable? (circle one)
   $0 $250 $500 $1000 $2000 $3000 $4000 $5000

Willingness-To-Pay Survey: Virginia Residential Consumers

Please read these notes prior to answering the questions:

1. According to a study by the Edison Electric Institute, the rate of outages on underground circuits is about one-third of that on overhead circuits.
2. Placing wires underground will significantly reduce, but not completely eliminate, outages during catastrophic storms, such as Hurricane Isabel.
3. Converting existing overhead circuits to underground will be expensive, costing up to one million dollars per mile or almost 10 times the cost of a new overhead power line, according to some estimates.
4. The North Carolina Public Utilities Commission recently estimated that it could take 25 years to underground the existing overhead distribution system in North Carolina and that customers' utility bills could double as a result. The amount paid by customers would be less if only a portion of the system were to be converted to underground or if costs were to be shared or subsidized.
5. The baseline cost to convert an individual's overhead service wire – from the utility pole to the residence – to underground cable in your yard is in the neighborhood of several hundred dollars, but could cost significantly more depending on specific circumstances.

Questions:

1. Is your current residence served by overhead or underground lines?
   Answer (overhead or underground)**:**
2. How many days were you without power from Hurricane Isabel?
   Answer**:**
3. How would you describe the reliability of your electric service?
   Answer (poor, fair, good, or excellent)**:**
4. Do you now own or plan to purchase a generator in the near future?
   Answer (yes or no)**:**
5. (Optional) What is your perception of your household income level?
   Answer (below average, average, above average)**:**

If you already have underground service, please proceed to question 9.

6. For purposes of responding to parts (a) and (b) below, assume the following two cost components for converting overhead utility wires to underground cable:
   - Burial of wires from the substation to the utility pole
   - Burial of the service wire from the utility pole to your residence and conversion of the meter base for compatibility with underground service

   (a) How much, if any, would you be willing to pay – in the form of a long-term permanent increase in taxes or utility bills – for conversion to underground service? (For this question, assume the payment only covers burial of those wires from the substation to your utility pole.)
   Answer (choose an amount from $0 to $100 per month)**:**

   (b) In addition to the monthly payment in (a), how much, if any, would you be willing to pay (in the form of a one-time fee) for removal of your utility pole and burial of the individual overhead service wire from your pole to your residence, and to have an electrician come to your residence and convert the meter base for underground service?
   Answer (choose an amount from $0 to $1000)**:**

7. How much more would you be willing to pay for a construction method (horizontal directional drilling, for example) that would eliminate the inconvenience and mess associated with trenching and backfilling?

   Answer (no more, somewhat more, substantially more)**:**
8. It probably will not be feasible to convert 100% of all overhead circuits in the state to underground. Furthermore, the conversion could take decades to complete, with no assurance that your circuit will be buried during your residence at your present location, if at all. How much would you be willing to pay for other higher priority circuits (for example, the least reliable or most unsightly circuits on the system) to be placed underground, with no guarantee that your circuit will ever be buried?

   Answer (choose an amount from $0 to $100 per month)**:**
9. (**To be answered only by customers who currently have underground service**). How much would you be willing to pay – in the form of a long-term permanent increase in taxes or utility bills – to provide underground service to those customers who currently have overhead service?

   Answer (choose an amount from $0 to $100 per month)**:**

APPENDIX G: FUNDING OPTIONS

PART I. LIST OF SIMPLE SINGLE-SOURCE FUNDING OPTIONS[123]

The following list of funding options was generated for the Commonwealth of Australia by the Economic Subcommittee of the Putting Cables Underground Working Group in 1997. The Working Group asked the Economic Subcommittee to investigate funding options for any program for putting cables underground. Funding options on the list range across the full spectrum of possible approaches, from philanthropy and corporate sponsorship at one end, through a wide range of options such as various forms of levies and consolidated revenue sources, contributions by various benefiting parties, voluntary arrangements between utilities and residents and/or private sector financing, to the raising of additional revenue by such methods as new taxes on CO_2 emissions and State lotteries at the other end. The Subcommittee noted that all these funding options were simple, broad single-source funding mechanisms only. They are described in greater detail immediately following the list.

1. New Government funding options
    a. Environmental taxes or levies
    b. Internet tax
    c. State lotteries
    d. Migration levies
2. Voluntary arrangements
    a. Proponents pay
    b. Industry/Community contracts
    c. Ratepayer/resident on voluntary basis
    d. Co-ordination with other works (technical rather than funding option)
3. Government consolidated revenue

    Consolidated revenue from ordinary tax/rates

    a. Tax relief through infrastructure bonds
    b. Local Government general revenue from rates
    c. Direct compulsion on local Government without specific compensation
    d. Government allowances to property owners engaged in undergrounding
    e. National Ducting Authority (regulatory rather than funding option)

    Consolidated revenue from asset sales

    f. Commonwealth revenue from Telstra sale
    g. Revenue from sale of State and Territory electricity companies

    Consolidated revenue from dividends

    h. Dividends from electricity companies owned by States and Territories

[123] *First Report on Funding Options*, Economic Subcommittee of the Putting Cables Underground Working Group, Commonwealth of Australia, 1997 (a)

4. Levies/charges/savings

Direct levies on ratepayers generally

a. Special rates collected by local Government

Direct levies on ratepayers/taxpayers in specific areas

b. Direct tax on benefiting individuals or local communities
c. Surcharge on rates in a specific area collected by local Government
d. Deferred surcharge on rates; paid when land sold

Fixed price surcharges levied generally and collected through utilities

e. Fixed annual levies on customers of utilities

Fixed price surcharges levied in specific areas and collected by utilities

f. Fixed annual levies on customers of utilities using overhead cabling

Variable consumption/usage-based price increases levied generally

g. Utilities capital & infrastructure renewal funds
h. Payment by utilities out of maintenance and other avoided costs
i. Electricity company pole attachment fees
j. Direct compulsion on utilities without specific compensation
k. Direct compulsion on some utilities to build ducts and others pay to use ducts
l. Levies on utilities/ increased carrier license fees
m. Local Government rents for airspace
n. Levies on all customers collected through higher usage tariffs/ specific utility tariffs

Variable consumption/usage-based price increases levied in specific areas

o. Levies on customers in specified areas collected through higher usage tariffs/ 'excluded service' charge

5. Funds from Commonwealth/State/Territory initiatives/programs

Existing programs

a. Natural Heritage Trust
b. Job programs/Work-for-the-Dole program
c. Federation Fund
d. State/Territory powerline relocation programs

New programs

e. New environment programs
f. New Government Initiative - 'Smart Cities'
g. New State/Territory Government Business Development Programs

6. Private sector mechanisms

a. Build/Own/Operate (BOO) joint venture
b. Build/Own/Transfer (BOT) joint venture

c. Build/Own/Operate/Transfer (BOOT) joint venture
d. Local council leaseback of infrastructure from investment companies
e. Common service trench
f. Public float by Government of shares in Ducting Authority
g. Superannuation funds
h. Private entrepreneurial
i. Corporate sponsorship
j. Philanthropy

PART II. DETAILS OF SIMPLE SINGLE-SOURCE FUNDING OPTIONS

1. New Government funding options

a. **Environmental taxes or levies**
The only one proposed to date is a tax on CO_2 emissions. This would have effects on the economy and industry far beyond the intended purpose of the tax. The Sub-Committee agreed that introducing a CO_2 tax just for an undergrounding program is not realistic.

b. **Internet tax**
A consumption tax on use of the Internet. This would have effects on the economy and the development of the information industries far beyond the intended purpose of the tax. The Sub-Committee agreed that introducing an Internet tax just for an undergrounding program is not realistic.

c. **State lotteries**
State lotteries such as those used to finance the Sydney Opera House. The Sub-Committee noted that the gambling market was fairly crowded already.

d. **Migration levies**
Taxes on migration. This would have effects on the economy and Australia's foreign policy far beyond the intended purpose of the tax. The Sub-Committee agreed that introducing migration levies just for an undergrounding program is not realistic.

2. Voluntary arrangements

a. **Proponents pay**
Those who desire undergrounding in an area, pay for it.

b. **Co-ordination with other works**
Undergrounding works would be co-ordinated with other municipal construction works, such as roads and sewerage. It was noted that this appears to be more of a technical option as to timing (which may reduce overall costs) than a funding option *per se*.

c. **Industry/Community Contracts**
Undergrounding arranged between local community and local electricity companies and carriers on funding basis as locally negotiated.

d. **Ratepayer on voluntary basis**
Electricity companies and carriers are required to underground for a property where the property owner pays for it. This is the current situation in relation to telecommunications subscriber connections (Telecommunications Code, Chapter 3).

3. Government consolidated revenue

Consolidated revenue from ordinary taxes/rates

a. **Tax relief through infrastructure bonds**
Contribution by Commonwealth Government from consolidated revenue through foregone tax revenue granted as tax deductions allowed on infrastructure bonds issued by financing institutions.

b. **Local Government general revenue from rates**
Local councils contribute from general rates revenue (eg. to cover savings from tree-prunings, or more generally to cover cost of undergrounding program)

c. **Direct compulsion on local Government without specific compensation**
Direct compulsion on local councils to fund or carry out an undergrounding program in their area, recovered from thier general rates revenue.

d. **Government allowances to property owners engaged in undergrounding, through subsidies or income tax relief**
Contribution by State/Territory or Commonwealth Governments from consolidated revenue through allowances or income tax deductions granted to property owners engaged in undergrounding.

e. **National Ducting Authority**
An authority is established by Commonwealth or co-operative legislation to build a common service trench in some or all areas. This is only useful if the best technical option involves co-location in one duct. This appears to be essentially a regulatory option rather than a funding option; funding could be by any means.

Consolidated revenue from asset sales

f. **Revenue from sales of State & Territory electricity companies**
Contribution from State/Territory consolidated revenue nominally from revenue received from sale of electricity companies.

g. **Commonwealth revenue from Telstra sale**
Contribution from Commonwealth consolidated revenue nominally from revenue received from part sale of Telstra.

Consolidated revenue from dividends

h. **Dividends from electricity companies owned by States & Territories**
Contribution from State/Territory consolidated revenue nominally from dividends received from electricity companies.

4. Levies/charges/savings

Direct levies on ratepayers generally

a. **Special rates collected by local Government**
State/Territory Goverments authorise or require local councils to increase rates to fund an undergrounding program.

Direct levies on ratepayers in specific areas

b. **Direct tax on benefiting individuals or local communities**
The State/Territory Goverment or Commonwealth Government levies a tax on all property owners in an undergrounding area, whether a flat charge or one variable in proportion to land value. Widely used in the United States.

c. **Surcharge on local Government rates in an area**
A surcharge on rates in an undergrounding area is levied and collected by the local council. The local council decides whether to levy a flat charge or vary the rate surcharge by land value.

d. **Deferred surcharges on property owners; paid when land sold**
As previous option, but a financing arrangement such as a private sector financed BOOT scheme or Government revenue is used to pay upfront costs of undergrounding.

Fixed price surcharges levied generally and collected through utilities

e. **Fixed annual levies on customers of utilities**
For example, a $300 annual 'connection' fee collected from all customers. This may be combined with a financing option such as a private sector financed BOOT scheme or Government revenue.

Fixed price surcharges levied in specific areas and collected through utilities

f. **Fixed annual levies on customers of utilities using overhead cabling**
For example, a $300 annual 'underground connection' fee collected from

customers with overhead cabling or customers who have had their cable undergrounded by the relevant undergrounding program (ie. other than by themselves). This may be combined with a financing option such as a private sector financed BOOT scheme or Government revenue.

Variable consumption/usage-based price surcharges levied generally

g. **Utilities capital & infrastructure renewal funds**
Local electricity companies and carriers are required to underground some or all of their aerial cabling as it comes up for replacement. This is not necessarily a sufficient source of funds to cover the additional costs of undergrounding.

h. **Payment by utilities out of maintenance and other avoided costs**
Requiring utilities to contribute to the extent of the likely savings to them on maintenance and other avoided costs. This is not necessarily a sufficient source of funds to fully cover the additional costs of undergrounding.

i. **Electricity company pole attachment fees**
Pole attachment fees would be regarded as a windfall benefit to electricity companies and this option would require them to be used for undergrounding programs.

j. **Direct compulsion on utilities without specific compensation**
There are two choices:

- Mandated undergrounding targets, whereby electricity companies and carriers would be required to underground a certain percentage of their networks by agreed target dates; or

- Undergrounding required in certain areas, as is the current situation in regard to electricity lines in greenfields areas. It is also the current situation in regard to telecommunications cables where other aerial cables have been undergrounded, including greenfields areas (Telecommunications Code).

It was recognized that the carriers and electricity companies would then pass on the costs to their customers, so that this is essentially a levy on customer usage.

k. **Direct compulsion on some utilities to build ducts - and on others to pay to use the ducts**
Mandation on either local electricity distribution company or a telecommunications carrier to build a duct and for others to pay to use it. This is only useful if the best technical option involves co-location in one duct. It was recognised that the carriers and electricity companies would then pass on the costs to their customers, so that this is essentially a levy on customer usage.

l. **Levies on utilities**
This would be a direct levy on carriers and electricity companies to pay for the cost of an undergrounding program, either by a new levy or by the use of existing mechanisms such as increased carrier licence fees. It was recognised that the

carriers and electricity companies would then pass on the costs to their customers, so that this is essentially a levy on customer usage.

m. **Local Government rents for use of airspace**
This would be a direct levy by local Governments on carriers and electricity companies using overhead cabling in their local council area to pay for the cost of an undergrounding program. It was recognised that the carriers and electricity companies would then pass on the costs to their customers, so that this is essentially a levy on customer usage (possibly on general customer usage to pay for local undergrounding).

n. **Levies on all customers collected through higher usage tariffs**
An example would be 2c on each local phone call, 0.1c per kW/h electricity usage State/Territory wide or nationwide, until undergrounding is completely paid for. If it is desired to underground first and collect money over time, this could be combined with a financing option such as a private sector financed BOOT scheme or Government revenue.

Variable consumption/usage-based price surcharges levied in specific areas

o. **Levies on customers in a specified area collected through higher usage tariffs**
An example would be 2c on each local phone call, 0.1c per kW/h electricity usage in undergrounding areas, until undergrounding is completely paid for in that area. If it is desired to underground first and collect money over time, this could be combined with a financing option such as a private sector financed BOOT scheme or Government revenue.

5. Funds from Commonwealth/State/Territory initiatives/programs

Existing Programs

a. **Natural Heritage Trust**
The Natural Heritage Trust has been established to promote a faster, more effective shift to ecological sustainability in Australia. The Commonwealth Government has stated that it will invest over $1.25 billion in the Trust while also establishing a capital base of $300 million to be retained in perpetuity to fund future environmental activities. Trust investment is to be used to stimulate significant improvement and greater integration of biodiversity, land, water and vegetation management on public and private land. It does not seem therefore to be directed at the kind of project under consideration by this Working Group.

b. **Job programs/ Work-for-the-Dole program**
A 12 month pilot program has been established to fund high-quality pilot projects specifically targeting young unemployed people and at the same time provide the opportunity for older workers to contribute. $12.4 million is available for the pilot project. Projects should be of value to the community and offer value for money.

Applications for the pilot scheme closed on 15 August 1997. The Commonwealth Government has now announced that it will be extending this scheme. Manly Council has written supporting use of this option.

c. **Federation Fund**
The purpose of the Federation Fund is to finance a number of major projects of national significance. $1 billion is available for the period to 2001. The projects are to be well advanced but not necessarily completed by the Centenary of Federation in 2001 and will be selected on the basis that they will generate jobs during construction and make a significant and ongoing contribution to Australia and the Australian economy. The projects targeted will be those in excess of $25 million and upwards.

d. **State/Territory powerline relocation funds**
WA, SA & Vic. all have existing powerline undergrounding or relocation programs on a pilot project level (WA) or using small-scale annual funding (SA, Vic.).

New Programs

e. **New environment programs**
New Commonwealth/State/Territory environment programs.

f. **New Government Initiative - 'Smart Cities'**
New urban regeneration programs.

g. **New State/Territory Government Business Development Programs**
New Government business development programs.

6. Private sector mechanisms

Joint ventures (BOO/BOT/BOOT schemes) *Under a joint venture, State/Territory Government and/or local Government and the private sector create a special purpose joint venture vehicle to build and own underground infrastructure. This is more a source of upfront finance than of ultimate funding. The money is recovered using any of the other proposed funding options* (Extensive regulatory considerations would be involved in the use of any of these methods. For example, in Victoria any such scheme might be required to be licensed and any network charges used to recover funds would be subject to Victorian electricity price controls.)

a. **Build/Own/Operate (BOO) scheme**
The special purpose vehicle builds the infrastructure and recovers the costs itself through specially authorized rates/taxes or usage charges/tolls

b. **Build/Own/Transfer (BOT) scheme**

The special purpose vehicle builds the infrstructure and transfers it to local or State/Territory Government which recovers the costs through specially authorised rates/taxes or usage charges/tolls;

c. **Build/Own/Operate/Transfer (BOOT) scheme**
The special purpose vehicle builds the infrastructure and recovers the costs itself through specially authorised rates/taxes or usage charges/tolls, ultimately transferring ownership to local or State/Territory Government.

<u>*Other private sector mechanisms*</u>

d. **Local council leaseback of infrastructure from investment companies**
Essentially a BOO scheme (see above) where funds are recovered by local councils leasing the infrastructure from the special purpose vehicle and paying for that out of rates or charges to utilities to both.

e. **Common service trench**
A common service trench is built by co-operation between local councils and the private sector. This is useful only if the best technical option involves co-location in one duct. This appears to be essentially a regulatory and upfront financing option rather than a funding option; funding could be by any means.

f. **Public float by Government of shares in Ducting Authority**
Public and other investors invest in undergrounding through a Ducting Authority, which recovers money as per any of the proposed funding methods. This appears to be more a source of upfront finance than of ultimate funding.

g. **Superannuation funds**
Superannuation funds may be a source of upfront financing for any program for putting cables underground, but are unlikely to serve as a funding source. Ultimately the finance will need to be repaid by another source of funding.

h. **Private entrepreneurial**
The investor receives a percentage of sale price of land at each sale in next 20 years, ie. taking a chance that property prices will increase as a result of undergrounding. An investor with rights in enough land could presumably securitize it and onsell to another financing source.

i. **Corporate sponsorship**
Corporate patronage. This may be one way for local communities to raise their share of funds (if any) - as appears to be the case in UK. This may help out for some communities in some areas, but generally relying on whole funding requirement to be sponsored by corporations seems somewhat optimistic. Besides, they will probably want overhead billboards in exchange.

j. **Philanthropy**
'Charity' dinners &c. This may be one way for local communities to raise their share of funds (if any) - as appears to be the case in UK. This may help out for some communities in some areas, but generally relying on whole funding requirement to be gifted by rich patrons seems somewhat optimistic.

PART III. EVALUATION OF THE FUNDING OPTIONS

The Australian Working Group developed a number of principles against which to evaluate the original list of 48 potential single-source funding options, and eventually adopted four viable funding options. The principles were designed to assist in considering whether any program of putting cables underground should proceed, who should decide whether it should proceed, and the equity and efficiency of different options for funding such a program.

In particular, the Working Group determined that funding options should be realistic and capable of being successfully implemented. Philanthropy and major corporate sponsorship, for example, were considered to fail this test. In addition, some initially proposed options were in fact financing mechanisms rather than funding options.

Another important principle in the Working Group's list was the desirability, on equity and efficiency grounds, that beneficiaries contribute funds to any program for putting cables underground in proportion to the benefits received by them. On this basis, the Working Group determined that for all funding options, any quantifiable benefits from putting cables underground should be identified and paid for by those enjoying the benefits. For example, utilities (that is, electricity distributors or telecommunications carriers) should contribute in proportion to any savings in maintenance costs; local government should contribute for savings in pruning of trees, and so on.

This led to the decision that all the funding options should, therefore, be a composite of (1) avoided costs paid by those making the savings and (2) the 'gap' that remains between the cost of putting cables underground and these quantified benefits. The key groups most likely to be involved with, or to benefit from, any program to put cables underground were determined to be the following:

- individual property owners and local residents in areas where cables are put underground;
- utilities;
- utility customers, especially those in areas where cables are put underground;
- local government for areas where cable is put underground;
- residents of a state or locality as a whole; and
- the nation as a whole.

Taking these considerations into account, four main funding options were adopted by the Working Group. Common to all options was that the stakeholders each pay their quantifiable avoided costs. The four options for funding the 'gap' that remains between the cost of undertaking the work and the quantified savings or costs avoided by putting the cable underground were:

1 property owners;

2 national, state or local utilities levy;

3 national, state or local consolidated revenue; or

4 property owners, with an additional component of contribution by the relevant national, state or local government.

The Working Group conducted a detailed evaluation of the four principle funding options against a number of economic and equity criteria, including effects on the overall economy and on the electricity and telecommunications industries in particular, and the degree of alignment between those who benefit and those who pay. Based on this evaluation, it was determined that a multi-contributor funding option best meets the criteria set by the working group. This model proposes that any organizations receiving quantifiable benefits as a result of underground conversion would contribute to the cost an amount at least equivalent to those benefits. The gap between the value of benefits and the total cost would be funded by property owners with some limited contribution by governments to reflect the broader community benefits.

APPENDIX H: CITY OF BOULDER PLAN

CITY OF BOULDER UNDERGROUNDING COST SHARE PROGRAM

C I T Y O F B O U L D E R

Department of Public Works/Transportation Division
P.O. Box 791
1739 Broadway
Boulder, Colorado 80306
(303) 441-3266

UNDERGROUNDING COST SHARE PROGRAM

The ***Undergrounding Cost Share Program*** assists city of Boulder individuals or groups of property owners with the undergrounding of existing overhead utilities adjacent to their property by sharing costs of the project through the use of the Xcel Energy Undergrounding Credit.

Program Background: The undergrounding credit is a feature of the City's franchise agreement with Xcel that requires Xcel to make available each year 1 percent of the preceding year's electric revenues from customers within the city for the purpose of undergrounding or reconfiguring electric distribution or transmission lines in streets and other public places. Approximately $150,000 per year is set aside on a non-cumulative basis to be used for Undergrounding Cost Share Program projects.

Program Information: The Undergrounding Cost Share Program provides up to $50,000 in matching funds to facilitate undergrounding projects. Program participants pay 50 percent of the estimated Xcel and Qwest costs up to $100,000; and 100 percent of estimated Xcel and Qwest costs over $100,000, as well as any other costs associated with the project such as work by private electricians. The maximum contribution from the Undergrounding Credit of $50,000 per project ensures that multiple projects can be funded each year.

Participant costs may vary widely depending on the length of the project, the type and number of facilities to be buried, and the work required. There are three components when determining costs:

- Cost to bury the main line along a street or alley, or through an easement. A rough cost estimate would be $75-$150 per foot for Xcel facilities, and $40-$80 per foot for Qwest facilities. Participants pay 50 percent of these costs.
- Cost to bury local services branching off the main line. If a residence or business is served by an overhead line connecting to the main line, burying this local service connection will cost an estimated $1,200 to $2,200. Participants pay 50 percent of these costs.
- Cost for any work by private electricians required to bury local services, such as bringing private service connections up to code or providing an outside service connection. If required, private electrician work may cost up to $2,000. Participants pay 100 percent of these costs.

Xcel must approve any proposed projects that do not extend a minimum of one city block or 750 feet, whichever is less. In addition, projects must be within the city limits of Boulder. In order to make undergrounding cost-effective, adjoining property owners may consolidate their efforts.

If appropriate locations for any transformers, switch cabinets and other required facilities are not available within the public right-of-way, participants provide easements on their properties for these facilities.

If the cost of projects requested in a year exceeds the available accrual set aside for that year, unfunded projects will be carried over for construction the following year. If the available accrual set aside is not used in a given year, the remainder will not be carried over to the next year.

Required undergrounding projects, such as undergrounding required due to physical conflicts with new construction or required as part of development approval, are not eligible for the Undergrounding Cost Share Program.

Program Process:

Step #1: Self-assessment -- determine if you qualify for the program, what you think undergrounding might cost you and if the program is cost-efficient for you. You may wish to speak to adjoining property owners to see if they're interested in participating with you.

Step #2: Contact Xcel (Ed Toombs, 303-938-2272) and Qwest (Kathy Dunbar, 303-441-7113) to determine undergrounding project feasibility and obtain no-charge preliminary cost ranges.

Step #3: Request engineering designs and cost estimates from Xcel and Qwest. Requesting parties will pay any required engineering costs directly to Xcel and Qwest. If the undergrounding project is constructed, any engineering costs will be credited to the requestor's half of costs.

Step #4: To move forward with participation in the program, requesting parties provide the City of Boulder Undergrounding Cost Share Program administrator (Joe Paulson, 303-441-3266) with copies of the engineering designs and cost estimates, specifying any engineering costs already paid.

Step #5: The city determines whether the current year's program balance is sufficient to fund the project or if it needs to wait until additional funding is available. When sufficient funding is available, the City approves the request for participation in the program.

Step #6: When project approval is received, the participant pays the City 50 percent of the Xcel and Qwest cost estimates, less any engineering costs already paid. The participant also provides to Xcel and Qwest any required easements.

Step #7: Upon receipt of the participant's share of the costs, the City directs Xcel and Qwest to proceed with scheduling and constructing the undergrounding project.

Projects proceed in the order that full payment and any required easements are received. Xcel will cooperate with any other utilities such as AT&T Cable TV to enable them to underground their facilities at no cost. The participant coordinates and pays directly for any other work required by the project not performed by Xcel or Qwest.

***Program Notes*:**

Qwest engineering cost estimates are firm; Xcel cost estimates are not. The participant cost-share is based on the estimated cost not the actual cost. Any Xcel cost overruns or savings are covered or absorbed by the Undergrounding Credit.

Undergrounding existing utilities is lower priority work for Xcel, Qwest, and AT&T than repairs and installing new services. Therefore, scheduling and constructing undergrounding projects may take several months after direction is given by the City to proceed.

***For more information*:** Contact Joe Paulson at the City of Boulder Transportation Division (303-441-3266).

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APPENDIX I: CALIFORNIA PLAN

PACIFIC GAS AND ELECTRIC COMPANY

RULE 20 UNDERGROUNDING PROGRAM

AND TARIFF

PG&E Rule 20 Electric Undergrounding Programs[124]

Pacific Gas and Electric Company ("PG&E") reportedly places approximately 30 miles of overhead facilities underground each year relative to projects performed in accordance with California Commission Rule 20. Projects performed under Rule 20A are nominated by a city, county or municipal agency and discussed with PG&E, as well as other utilities. The costs for undergrounding under Rule 20A are recovered through electric rates after the project is completed. Rule 20 also includes sections B and C. The applicability of sections A, B or C is determined by the type of area to be undergrounded and by who pays for the work.

Typically, Rule 20A projects are located in the areas of a community that are used most by the general public. These projects are also paid for by all customers through future electric rates. To qualify as a Rule 20A project, the governing body of a city or county must determine – after consulting with PG&E and holding public hearings – that undergrounding is in the general public interest for one or more of the following reasons:

- Undergrounding will avoid or eliminate an unusually heavy concentration of overhead electric facilities.
- The street or road or right-of-way is extensively used by the general public and carries a heavy volume of pedestrian or vehicular traffic.
- The street or road or right-of-way adjoins or passes through a civic area or public recreation area or an area of unusual scenic interest to the general public.

Rule 20B usually applies to larger developments. The majority of the costs are paid for by the developer or applicant. Undergrounding under Rule 20B is available in circumstances where the area to be undergrounded does not fit the Rule 20A criteria but still involves both sides of the street for at least 600 feet. Under Rule 20B, the applicant is responsible for the installation of the conduit, substructures and boxes. The applicant then pays for the cost to complete installation of the underground electric system, less a credit for an equivalent overhead system, plus the ITCC (tax), if applicable.

Rule 20C typically encompasses smaller projects involving a few property owners, and the costs are almost entirely borne by the applicants. Undergrounding under the provisions of Rule 20C is available where neither Rule 20A nor Rule 20B applies. Under Rule 20C, the applicant pays for the entire cost of the electric undergrounding, less a credit for salvage.

According to PG&E, a cross-functional team that includes representatives from PG&E, the phone and cable companies, local governments and the community at-large oversees Rule 20A projects. Projects generally last three years and are accomplished by:

- Identifying and reviewing potential projects
- Developing preliminary costs for the projects

[124] "Rule 20 Electric Undergrounding Program," Pacific Gas & Electric Company, 2004, http://www.pge.com/field_work_projects/street_construction/rule20/, (8 December 2004)

- Refining associated boundaries and costs
- Coordinating the schedules of other public works projects
- Developing final project plans
- Passing a municipal underground resolution
- Developing an underground design
- Converting service panels for underground use
- Starting construction
- Installing underground services
- Completing all street work
- Removing existing poles from the project

PG&E's Rule 20 Tariff is provided on the following pages.

PG&E TARIFF – RULE 20

A. PG&E will, at its expense, replace its existing overhead electric facilities with underground electric facilities along public streets and roads, and on public lands and private property across which rights-of-ways satisfactory to PG&E have been obtained by PG&E, provided that:

1. The governing body of the city or county in which such electric facilities are and will be located has:

    a. Determined, after consultation with PG&E and after holding public hearings on the subject, that such undergrounding is in the general public interest for one or more of the following reasons:

        1) Such undergrounding will avoid or eliminate an unusually heavy concentration of overhead electric facilities;

        2) The street or road or right-of-way is extensively used by the general public and carries a heavy volume of pedestrian or vehicular traffic;

        3) The street or road or right-of-way adjoins or passes through a civic area or public recreation area or an area of unusual scenic interest to the general public; and

        4) The street or road or right-of-way is considered an arterial street or major collector as defined in the Governor's Office of Planning and Research General Plan Guidelines.

    b. Adopted an ordinance creating an underground district in the area in which both the existing and new facilities are and will be located requiring, among other things, (1) that all existing overhead communication and electric distribution facilities in such district shall be removed, (2) that each property served from such electric overhead facilities shall have installed in accordance with PG&E's rules for underground service, all electrical facility changes on the premises necessary to receive service from the underground facilities of PG&E as soon as it is available, and (3) authorizing PG&E to discontinue its overhead service.

2. PG&E's total annual budgeted amount for undergrounding within any city or the unincorporated area of any county shall be allocated as follows:

    a. The amount allocated to each city and county in 1990 shall be the highest of:

        1) The amount allocated to the city or county in 1989, which amount shall be allocated in the same ratio that the number of overhead meters in such city or unincorporated area of any county bears to the total system overhead meters; or

        2) The amount the city or county would receive if PG&E's total annual budgeted amount for undergrounding provided in 1989 were allocated in the same ratio that the number of overhead meters in each city or the unincorporated area of each county bears to the total system overhead meters based on the latest count of overhead meters available prior to establishing the 1990 allocations; or

        3) The amount the city or county would receive if PG&E's total annual budgeted amount for undergrounding provided in 1989 were allocated as follows:

a) Fifty percent of the budgeted amount allocated in the same ratio that the number of overhead meters in any city or the unincorporated area of any county bears to the total system overhead meters; and

b) Fifty percent of the budgeted amount allocated in the same ratio that the total number of meters in any city or the unincorporated area of any county bears to the total system meters.

b. Except as provided in Section 2.c., the amount allocated for undergrounding within any city or the unincorporated area of any county in 1991 and later years shall use the amount actually allocated to the city or county in 1990 as the base, and any changes from the 1990 level in PG&E's total annual budgeted amount for undergrounding shall be allocated to individual cities and counties as follows:

1) Fifty percent of the change from the 1990 total budgeted amount shall be allocated in the same ratio that the number of overhead meters in any city or unincorporated area of any county bears to the total system overhead meters; and

2) Fifty percent of the change from the 1990 total budgeted amount shall be allocated in the same ratio that the total number of meters in any city or the unincorporated area of any county bears to the total system meters.

c. When a city incorporates, resulting in a transfer of utility meters from the unincorporated area of a county to the city, there shall be a permanent transfer of a prorata portion of the county's 1990 allocation base referred to in Section 2.b. to the city. The amount transferred shall be determined:

1) Fifty percent based on the ratio that the number of overhead meters in the city bears to the total system overhead meters; and

2) Fifty percent based on the ratio that the total number of meters in the city bears to the total system meters.

When territory is annexed to an existing city, it shall be the responsibility of the city and county affected, in consultation with the Utility serving the territory, to agree upon an amount of the 1990 allocation base that will be transferred from the county to the city, and thereafter to jointly notify PG&E in writing.

d. However, Section 2 a, b, and c shall not apply to PG&E where the total amount available for allocation under Rule 20-A is equal to or greater than 1.5 times the previous year's statewide average on a per customer basis. In such cases, PG&E's total annual budgeted amount for undergrounding within any city or the unincorporated area of any county shall be allocated in the same ratio that the number of overhead meters in the city or unincorporated area of any county bears to the total system overhead meters.

e. Upon request by a city or county, the amounts allocated may be exceeded for each city or county by an amount up to a maximum of five years' allocation at then-current levels where PG&E establishes additional participation on a project is warranted and rsources are available. Such allocated amounts may be carried over for a reasonable period of time in communities with active undergrounding programs. In order to qualify as a community with an active undergrounding program the governing body must have adopted an ordinance or ordinances creating an underground district and/or districts as set forth in Section A.1.b. of this Rule. Where there is a carry-over or additional requested participation, as discussed above, PG&E has the right to set, as determined by its capability, reasonable limits on the rate of performance of the work to be financed by the funds carried over. When amounts are not expended or carried over for the community to which they are initially allocated they shall be assigned when additional participation on a project is warranted or be reallocated to communities with active undergrounding programs.

3. The undergrounding extends for a minimum distance of one block or 600 feet, whichever is the lesser.

   Upon request of the governing body, PG&E will pay from the existing allocation of that entity for:

   a. The installation of no more than 100 feet of each customer's underground electric service lateral occasioned by the undergrounding.

   b. The conversion of electric service panels to accept underground service, up to $1,500 per service entrance, excluding permit fees.

      The governing body may establish a smaller footage allowance, or may limit the amount of money to be expended on a single customer's electric service, or the total amount to be expended on all electric service installations in a particular project.

B. In circumstances other than those covered by A above, PG&E will replace its existing overhead electric facilities with underground electric facilities along public streets and roads or other locations mutually agreed upon when requested by an applicant or applicants when all of the following conditions are met:

1. a. All property owners served from the overhead facilities to be removed first agree in writing to have the wiring changes made on their premises so that service may be furnished from the underground distribution system in accordance with PG&E's rules and that PG&E may discontinue its overhead service upon completion of the underground facilities; or

   b. Suitable legislation is in effect requiring such necessary wiring changes to be made and authorizing PG&E to discontinue its overhead service.

2. The applicant has:

   a. Furnished and installed the pads and vaults for transformers and associated equipment, conduits, ducts, boxes, pole bases and performed other work related to structures and substructures including breaking of pavement, trenching, backfilling, and repaving required in connection with the installation of the underground system, all in accordance with PG&E's specifications, or, in lieu thereof, paid PG&E to do so;

   b. Transferred ownership of such facilities, in good condition, to PG&E; and

   c. Paid a nonrefundable sum equal to the excess, if any, of the estimated costs, of completing the underground system and building a new equivalent overhead system.

3. The area to be undergrounded includes both sides of a street for at least one block or 600 feet, whichever is the lesser, and all existing overhead communication and electric distribution facilities within the area will be

4. PG&E may, when requested by the city or county and mutually agreed upon by such government entity and PG&E, intitially fund any required engineering/design costs for conversion projects under this section. In the even such a project proceeds, the requesting city or county shall reimburse PG&E for such engineering/design costs before PG&E shall be required to commence further work on the project. In the event the project is not approved to proceed within two and one-half years of PG&E's delivery of such engineering/design study, the requesting city or county shall reimburse PG&E for its costs of such engineering/design study within 90 days of a demand by PG&E. In the event payment is not received PG&E shall expense such costs as an operational cost and shall reduce the city or county's allocations provided under Section A of this Schedule by the amount.

5. The costs of removal of the overhead poles, lines, and facilities are the responsibility of PG&E and will be paid by PG&E. Such payments shall not operate to reduce Rule 20-A allocations.

C. In circumstances other than those covered by A or B above, when mutually agreed upon by PG&E and an applicant, overhead electric facilities may be replaced with underground electric facilities, provided the applicant requesting the change pays, in advance, a nonrefundable sum equal to the estimated cost of the underground facilities less the estimated net salvage value and depreciation of the replaced overhead facilities. Underground services will be installed and maintained as provided in PG&E's rules applicable thereto.

D. The term "underground electric system" means an electric system with all wires installed underground, except those wires in surface mounted equipment enclosures.removed.