Utility's Strategic Application of Short Underground Transmission Cable Segments Enhances Power System

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***Abstract* — Overhead lines are generally the preferred means to transfer power due to their generally lower cost and higher transmission capacity, particularly in rural settings, as compared to power cables. However, underground transmission segments can be important links in transmission circuits where lines are impractical. One utility uses strategic applications of cable segments to build transmission lines and enhance the power system through in-station ties. This comes with various challenges including matching overhead line or station bus capacity, reliability considerations, supporting a viable inventory of spare parts, and coordinating construction activities around available outages. This paper summarizes the design choices and project challenges considered during implementation of six cable projects on the Delmarva peninsula in 2012 and 2013 that significantly expanded the reliability of the utility's power system.**

I. INTRODUCTION

Delmarva Power & Light Company (DPL) serves the Delaware and Maryland peninsula with approximately 2,500 km (1,550 miles) of transmission circuits. As part of a project to reinforce portions of the system, new transmission has been added in response to utility system studies and the regional transmission organization's (PJM serves the area) requirements for expanded capacity for normal and "N-1-1" contingency ratings. Much of the new transmission and substation reinforcing of the utility's system involves construction of overhead transmission lines, reflecting the relative low population densities and vast stretches of land dedicated to farming and agriculture. However, several of DPL's circuits must enter congested substations or require tying parts of the substations together where there existed overhead lines or substation bus. The application of power cables was the only option for meeting the various projects requirements (locations are shown in Fig. 1).

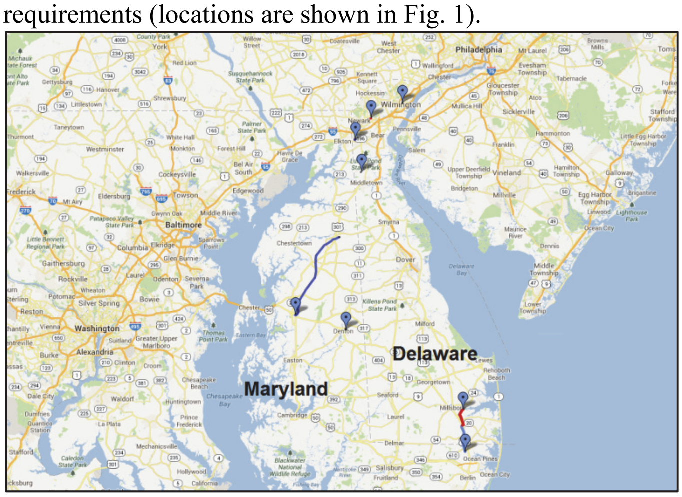

Figure 1: Locations of utility's recent cable projects

Historically, the utility had frequently selected EPR-insulated cable for 69kV and 138kV substation dips for overhead lines; several of the circuits used 2 cables per phase. Manufacturing constraints for this cable insulation type limit the conductor size to approximately 1000mm^2 (2000kcmil) compact round copper. In many cases, these smaller cable sizes permitted construction and installation practices that could be extended from distribution practice. However, as the transmission and substation reinforcing projects moved forward, it became evident that higher capacity cables would need to be considered, along with some alternative construction approaches.

Many design decisions were made to meet the loading, reliability and installation requirements of multiple projects. The following sections describe these many details.

II. DESIGN CHALLENGES FOR UNDERGROUND

A. Cable System Alternatives

Extruded power cables were the only cable type considered for the projects. The utility had historically used 138kV ethylene-propylene rubber (EPR) insulated cables with conductor sizes up to 1013mm^2 (2000kcmil) compact round conductors. Only one manufacturer commercially offered EPR cable at 138kV, with the 2000kcmil-size as an upper manufacturing limit. This presented challenges for several DPL's projects.

- Cable Insulation and Conductor Type: First and foremost, the 2000kcmil size with a compressed round conductor was insufficient to meet rating goals for the projects. Many manufacturers of transmission cables offering conductor sizes above 633mm^2 (1250kcmil) use segmental conductors to improve AC resistance characteristics. Segmental conductors have about 3-13% greater ampacity than comparably sized compact round conductors. An equivalent compact round conductor would require a larger conductor (requiring greater material cost) and was not commercially available for EPR. This drove the projects towards using cross-linked polyethylene (XLPE) insulation. XLPE-insulated cable is commercially available from multiple suppliers both domestically in the United States and overseas.
- Diversity of Supply: Second, with only one manufacturer available to offer EPR cable, production lead times and diversity of supply were concerns. The utility wanted assurance that the cable selected for the project would have a wider range of suppliers that could competitively bid on the cable system. Transmission cable and their associated accessories (splices, terminations) are subjected to a qualification test using only one manufacturer's system of components, generally meaning that components are not fully interchangeable among manufacturers. However, there was consideration that application of a common XLPE-insulation technology for the higher-capacity circuits

would potentially offer some interchangeability in the event that emergency restoration was ever necessary.

- Concerns about Termination Reliability: Leading up to the time of the first of this series of projects, there had been some termination failures effecting existing 138kV EPR-insulated cables. The utility considered that an alternative cable system should be considered to improve reliability while also addressing the needs of higher capacity cable alternatives.

B. *Cable Size Selection and Ampacity*

One of the considerations for selecting the cable system was the number of cables per phase to use for each circuit which, in turn, affects the conductor size needed to achieve the required ampacity. With multiple cables per phase, the current carrying capacity is shared among all of the cable phases, but the load is not always shared equally among the cables. Historically, DPL had used two cables per phase for many of their 138kV projects – many of which were short substation dips – to match the required ampacity of the connected overhead transmission lines to which the cables were connected. The cables had predominantly been 2000kcmil compact round EPR cables, but the capacity was capped by the conductor size limit and compact round construction.

XLPE-insulated cables are available commercially with sizes up to 2600mm^2 (5131kcmil) depending on manufacturer with segmental constructions. This range of sizes resulted in many choices for conductor selection. Figure 2 shows the variation in rating versus conductor size; note that with two cables per phase, the per-cable rating with two cables / phase is approximately 88% (not 100%) of the single-cable rating.

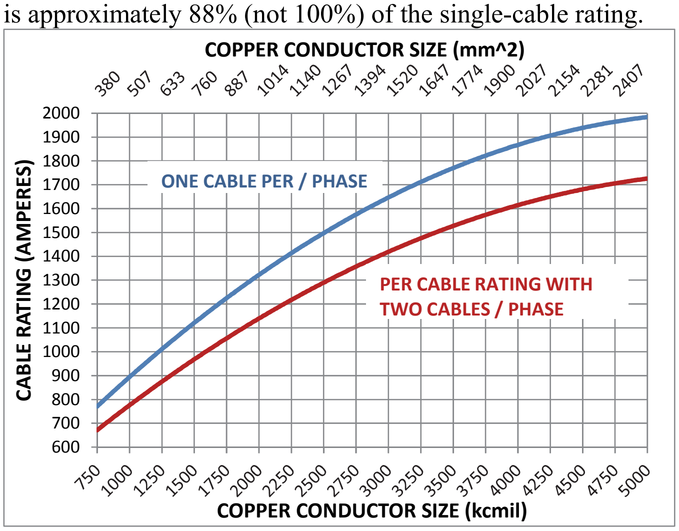

Figure 2: Variation in ampacity as a function of conductor size

The circuit rating can be based on many factors including utility system planning studies or matching the capacity of another component (overhead line, transformer) that is along the circuit; the latter was the basis for these projects. Cables often have lower normal ratings than other transmission equipment, particularly overhead lines, but much higher emergency rating capabilities – particularly short-duration emergencies -- due to the long thermal time constant of cables and the mass of earth in which they are installed; normal ratings, not emergency ratings, were driving the conductor selections for these projects.

C. *Reliability and Redundancy Considerations*

As DPL historically needed two cables per phase to meet the rating requirements with the maximum available EPR cable sizes, this had become somewhat of a defacto standard. However, with consideration of XLPE cables, many of the circuits could be designed with one cable per phase. Though cables generally experience fewer failures than overhead lines, mostly due to immunity from weather effects, when failures do occur the restoration time can be much longer (days to weeks) than for overhead (hours to days). If a failure does occur and it is isolated to just one set of cables, usually some limited efforts can be applied to isolate the failed cable and restore at least partial power transfer with the remaining circuit; this usually involves using two smaller cables (than would be required for one cable per phase) but requiring twice as many terminations and, if necessary, splices.

Complicating matters, however, is that accessories, not the cable, are generally more prone to failures because they are subjected to workmanship and environmental issues during their installation and potentially more susceptible to mechanical damage from thermal-mechanical movement. Therefore, other factors held constant, introducing a system that has more accessories will inherently have lower reliability than a system with fewer accessories. Despite redundancy, splices in common manholes or terminations in close proximity on common structures that experience failures could result in both adjoining circuits' accessories failing. Adding two cables per phase for shorter circuits does not always provide benefits in terms of reliability or shortened restoration time.

For shorter length circuits, the probability of a cable circuit failure affecting the cable is significantly lower than for a longer circuit, so limiting designs to one cable per phase may be prudent. The single-cable-per-phase approach also simplifies riser structures and transition poles.

DPL used both approaches (one cable or two cables per phase) on their projects reflecting balances between perceived enhancements in reliability and simplified (and less costly) duct banks, civil works and transition structures and poles.

D. *Sheath Bonding*

Many transmission cable circuits are constructed with cross-bonded sheath connections that transpose the sheath connections along the route to nullify circulating currents (multi-point bonding / short-circuited sheaths are generally only used for submarine transmission circuits).

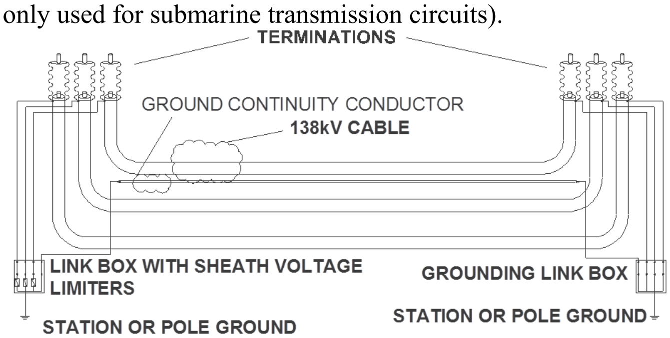

Figure 3: Single point bonding scheme used for cable projects

Because the cable circuit lengths used by the utility were all short (the longest circuit was less than 850m [2800ft], and some were less than 65m [200ft]), only single-point bonding of the cable sheaths was considered for these projects to eliminate circulating current losses and maximize ampacity. In fact, all but one of the circuits was constructed with a single pulling section. Single phase or three phase link boxes were used, and some circuits had two cables per phase. Figure 3 shows the configuration with only one cable per phase. To manage induced cable sheath/metallic shield voltages during normal and fault conditions, sheath voltage limiters (are placed at the "open" end of the cable run to clamp the voltage below 3-5kV.

E. Civil Methods and Pulling Tension Considerations

Cable systems are usually installed by "open cut" trenching from the surface to install conduit bundles that are back-filled with high-strength concrete. Horizontal bending radii for duct runs are ideally greater than 6-10m (20-30ft) to minimize sidewall bearing pressure and pulling tension forces.

Figure 4: Open cut excavation

Figure 5 shows a 2x4 duct bank configuration with 168mm (6.625in) conduits, and Figure 6 shows an example cable duct bank with a 2x2 configuration with 220mm (8.625in) conduits, both of which were used on these projects at DPL.

Near riser structures, 90° vertical sweeps are possible, but these are usually small 2-2.5m (6-8ft) in diameter and can generate significant increases in pulling tensions and sidewall bearing pressure forces. For this reason, DPL's circuits were installed with direct buried sections near riser structures and transition poles as shown in Fig. 7.

Figure 5: 2x4 duct bank, with 6-in conduits and 9-5/8in center-line separation

Figure 6: 2x2 duct bank (left) and concrete backfill installation (right)

Also, since accessories are more prone to failure than the cable itself, a direct buried section can permit a termination repair without installing replacement cable; the direct buried section is excavated, the damaged cable end cut off, and the cable slack pulled up to build a replacement termination. The direct buried section also permits phasing adjustments if required. Below riser structures, partial pieces of conduit were put over the cables to provide mechanical protection, along with a shallow layer of thermal sand to separate the cables from the Fluidized Thermal Backfill (FTB) used in these areas (right of Fig. 7).

Figure 7: Direct buried section near a compact transition pole with one cable per phase (left) and conventional risers with two cable per phase (right)

A third civil method (see Fig. 8), pipe-jacking, was used for crossing under a railroad siding near Indian River Substation encountered along the route of one circuit. In this location, pipe-jacking was attempted.

Figure 8: Pipe-jacking operation under rail sidings

In pipe-jacking, a large auger is used to install a casing pipe through which conduits can be installed for the power cables. This normally avoids the need for surface excavation which is generally prohibited for rail and major road crossings.

III. Project Descriptions and Characteristics

A. Utility Need

Due to the Northeast Blackout in 2003, the North American Electric Reliability Corporation (NERC) developed more stringent reliability standards requiring interconnected transmission systems be "N-1-1" compliant by 2013. As a result, DPL identified a number of projects to resolve N-1-1 thermal and/or voltage violations, including the work identified at Harmony, Glasgow, Indian River, Bishop, Mount Pleasant, and Steele. These system enhancements present increased reliability on the transmission system in the event planned or unplanned transmission events occur.

B. Selected Cable Designs

The various cable projects all required short lengths of cable either to connect two remote bus locations within the same substation (essentially bus ties) or to provide an underground link from an overhead line to enter a substation. Indian River-Bishop was a project conceived as only an overhead transmission line along a 19.4km (12 mile) circuit from Delaware to Maryland. Similarly, the cable circuit near Glasgow Substation was part of a 17.7km (11 mile) circuit. Other projects were strictly within substations.

Prior to these projects, DPL had somewhat standardized on 2 x 2000kcmil EPR cable constructions. The Harmony project, followed closely by Glasgow, Mt. Pleasant and Brandywine, were all ready to begin procurement at about the same time. The higher capacity design needed for Harmony drove the cable size selection, but the other cable circuits were constructed using the same cables from the same manufacturer to allow some standardization and permit interchangeability of spare parts. These projects all used cables with 1000mm^2 segmental copper conductors, 16mm of insulation, lead alloy sheath and polyethylene jacket (Fig 9, left).

The Steele project had station clearance constraints if a wider, double-terminator structure had been used so a single 2500mm^2 segmental copper conductor cable was selected with 18mm of insulation, copper shield wires, aluminum foil laminate sheath and polyethylene jacket (see Fig. 9, right).

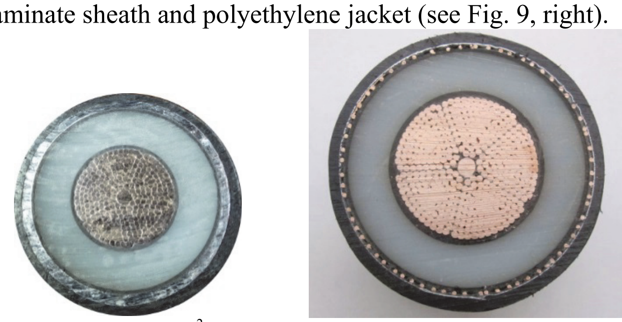

Figure 9: (left) 1000mm^2 Cable used at Harmony, Glasgow, Mt Pleasant, and Brandywine Substations (94mm), and (right) 2500mm^2 cable used at Steele Substation (122mm), both from Brugg Cables' factory in Switzerland

Space constraints for the breaker-and-a-half configuration at Indian River and Bishop did not permit two cables per phase so a 2534mm^2 (5000kcmil) segmental copper conductor cable with 18mm of insulation, copper shield wires, a copper foil laminate and polyethylene jacket (Fig. 10) was used; this was the first U.S. application of 5000kcmil 138kV cable.

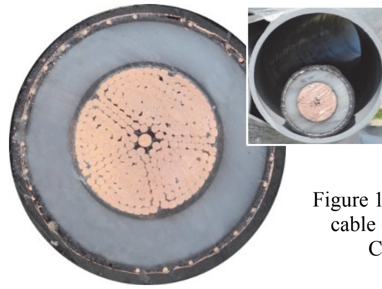

Figure 10: Indian River–Bishop 5000kcmil cable (119mm) from Prysmian Wire & Cable's Abbeville, SC factory (inset: in 8in conduit).

Due to their size, the 1000mm^2 cables were installed in 6in conduits, and the 5000kcmil and 2500mm^2 cables were installed in 8in conduits. Table I summarizes the overall cable system characteristics and selected cable sizes.

TABLE I
CABLE PROJECT SUMMARY

Circuit Name	Install Year	Circuit Type	Circuit Length	Required Rating Normal / 4hr	Selected Cable Construction
Indian River	2012	OH-UG	845m	1889A / 2286A	5000kcmil, segmental Cu
Bishop	2012	OH-UG	260m	1641A / 2030A	5000kcmil, segmental Cu
Harmony	2013	Bus Tie	210m	2200A / 2500A	2 x 1000mm^2, segmental Cu
Brandywine	2013	Bus Ties	80m 65m	2000A 600A	2 x 1000mm^2, segmental Cu (both circuits)
Glasgow	2013	OH-UG	63m	1632A / 2020A	2 x 1000mm^2, segmental Cu
Mt. Pleasant	2013	Bus Tie	200m	1632A / 2020A	2 x 1000mm^2, segmental Cu
Steele	2013	Bus Tie	106m	2000A	2500mm^2, segmental Cu

C. Locations, Routes, Environment and Construction

The circuit locations were all within fenced utility substation property or just outside of the secure substation areas. Therefore, many of the typical challenges of underground projects such as traffic control, pavement restoration, extensive permitting, easement procurement, etc. were significantly reduced. However, an issue that required coordination was scheduling station outages for civil work, cable pulling and installation of terminations. Outages had to be coordinated with the regional transmission organization and expected peak load times.

The routes all had generally level elevations except for Brandywine where there were 5-7m of elevation change over the short circuit length. Soil tests showed generally low thermal resistivity, and the utility's rating standards for summer and winter ambient temperatures were factored into ampacity calculations. De-watering was a factor at many of the locations due to the relatively shallow water table. Well point systems and submersible pumps were both used to manage water intrusion into the trenches.

D. Manufacturing and Quality Assurance

All of the cables supplied were in response to detailed specifications issued by the utility. These specifications, including extensive factory acceptance test requirements, were used to hold the cable manufacturers accountable for providing quality cable. Association of Edison Illuminating Companies (AEIC) CS9 and IEC 60840 were both used as a basis for the test requirements on the projects. Field commissioning tests were also performed.

IV. Acknowledgments

Cable installation work for all of the projects was performed by New River Electrical Corporation of Cloverdale, Virginia; New River also performed some of the civil works including installation of portions of the duct banks and direct buried sections. GeothermUSA of Dublin, California performed in situ and laboratory analyses of soils along all the cable routes and assisted with sourcing fluidized thermal backfill (FTB) from local suppliers. The authors provided design, detailed engineering support and project oversight during procurement, construction, installation and commissioning.

V. Conclusions

Through coordinated and strategic application of underground transmission cables at focused points within the power system, a utility was able to significantly reinforce the power transfer capabilities and enhance overall reliability and customer service with minimal impact on existing infrastructure. By carefully designing these systems, the cables avoid being thermal bottlenecks on circuit transfer capabilities. The considerations addressed during these projects will be lessons learned for future work done by the utility as they develop standards for underground systems.

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VII. Biographies

Earle C. (Rusty) Bascom, III (M’1989-SM’) holds B.S. and M.E. degrees in Electric Power Engineering from Rensselaer Polytechnic Institute and an M.B.A. from the University of New York at Albany. Mr. Bascom began his career in 1990 working with underground cable systems at Power Technologies, Inc. and, later, Power Delivery Consultants, Inc. before founding Electrical Consulting Engineers, P.C. in 2010 where as a Principal Engineer he continues to provide engineering services in the analysis, design, specification, installation oversight and operational characteristics of underground and submarine transmission and distribution cable systems. He is a Senior Member of the IEEE, Power & Energy Society, a Voting Member of the Insulated Conductors Committee and Standards Association, a member of CIGRÉ, and a registered professional engineer in NY, FL and TX. He can be contacted at r.bascom@ec-engineers.com.

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