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EVALUATION OF THE ECONOMICAL AND TECHNOLOGICAL VIABILITY OF VARIOUS UNDERGROUND TRANSMISSION SYSTEMS FOR LONG FEEDS TO URBAN LOAD AREAS

FINAL REPORT

DECEMBER 1977

PREPARED FOR

U.S. DEPARTMENT OF ENERGY

DIVISION OF ELECTRIC ENERGY SYSTEMS

UNDER CONTRACT EX-77-C-01-2055

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Electric Power Research Institute
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APPENDIX II

1. INTRODUCTION

The goal of this program was to evaluate many of the bulk power underground transmission systems that may be available in the 1990's and to determine their suitability for inclusion in power systems, both technologically and economically. A theoretical expansion of the Pennsylvania-New Jersey-Maryland (PJM) Interconnection to approximately three times its present size was used as the base system for the study. A 10,000 MW generation park, hereafter referred to as Energy Park, was added to the base system at a location remote from principal load centers.

No attempt was made to study large generation parks. The large amount of generation assumed in Energy Park was necessary since some of the transmission systems included are not suitable for low power applications. The Energy Park concept also provided a method whereby a number of constraints such as unit availability and construction timing could be included.

The assumed location of Energy Park is a site on the Susquehanna River 106 km (66 miles) from the termination of the transmission system at a location in Philadelphia, hereafter referred to as Mid-Site Substation (see Figure 3-1). The latter site was chosen as a typical location for transformation from the transmission network to the system supplying a large urban area.

The transmission route selected corresponds to an existing aerial right-of-way. Consequently, a complete plan and profile of the right-of-way was available for the study. The route selected traverses a wide range of environments from rural farmland near the Energy Park, to suburban areas, and finally to a densely-populated urban area along the last 10 km (6 miles) of the right-of-way. Existing transmission structures were ignored and the installation of the cables planned as if the right-of-way had been obtained specifically for this application. The cost of right-of way was included in the study as if it had to be purchased.

Common right-of-way and common system ampacity requirements provided a uniform application to evaluate the sixteen transmission systems included in the study. The reliability requirements and ampacities under contingency conditions were also applied uniformly to each of the systems.

Analysis of each system proceeded as if it were being evaluated for an actual application, although Philadelphia Electric Company has no plans at present to construct any of the systems studied. All systems were included in the projected PJM base electric system, and loadflow and stability studies were conducted for both radial and network applications with specific substation arrangements. The network case differs from the basic radial case in that it assumes the Energy Park substation to be connected to the existing 500 kV aerial system at a substation near Energy Park.

Series and shunt compensation installations were included where indicated. Completed designs were costed, and capitalized costs of operating losses and maintenance were included. All costs were extended through two 40-year life cycles to give present worth of future revenue requirements.

Care must be exercised in applying the results of this study, since they were obtained for a single set of application parameters. Changes in design parameters, ampacity requirements, cost of losses, and numerous other factors could affect the results. Since the time period under study is approximately 1995, some assumptions were made as to developments that would occur during the next twenty years. For example, the cost of gas-insulated transmission

1. <u>INTRODUCTION</u> (cont'd)

lines is assumed to be approximately sixty percent of present costs. This reduction in cost would be feasible if present small-scale manufacturing techniques should grow into mass-production facilities. Another example is the assumed dissipation factor, and consequently the assumed losses, for flexible ac superconducting cable, which are significantly below values for present-day materials. However, future developments might well reduce losses to the assumed level.

2. SUMMARY

Table 2-1 summarizes the Adjusted Grand Total Cost of each of the systems studied, based on economic analysis for a radial connection. Breakdowns of costs and costs for the network connection are given in the individual chapters on each system. A description of the Adjusted Grand Total is given in Section 3.2.3.

In discussing the final results of the economic analysis, several notes of caution must be considered.

First, the results included in this summary are for the specific problem assigned and cannot be applied universally to all underground transmission applications.

Second, several of the systems studied have never been installed on a utility system. Consequently, the cost of these cables as well as their installation costs are not known as accurately as those systems which are commercially available. However, every attempt was made to project probable developments in technology and commercial availability as fairly and uniformly as possible.

Third, some systems which do not appear to have the lowest cost in the problem specified in this study would be the economical choice for a lower ampacity application or for a shorter length.

Fourth, compensation requirements and evaluation of losses have had a considerable impact. Different methods or philosophies of operation or of evaluation of losses could also change the relative position of the various systems.

2. SUMMARY (cont'd)

Fifth, the terminology "dollars per MVA mile" has not been used in this study because this type of comparison can provide fictitiously low values for high ampacity systems. After conducting loadflow and stability analyses, the usable ampacity of the systems is usually found to be well below the theoretical value. Consequently, total cost for an application is the only accurate method of comparison.

Table 2-1

Executive Summary Table

Underground Systems	Acronym	Radial System Adjusted Grand Total - $K
500 kV HPOPT Cellulose-Insulated Cable	500 kV HPOPT-C	1,879,191
500 kV HPOPT PPP-Insulated Cable	500 kV HPOPT-PPP	1,562,674
765 kV HPOPT PPP-Insulated Cable	765 kV HPOPT-PPP	1,682,270
500 kV Force-Cooled HPOPT PPP-Insulated Cable	500 kV HPOPT-F/C	1,766,735
765 kV Force-Cooled HPOPT PPP-Insulated Cable	765 kV HPOPT-F/C	1,761,224
500 kV AC Self-Contained Oil-Filled Cable	500 kV SCOF-AC	1,364,795
600 kV DC Self-Contained Oil-Filled Cable	600 kV SCOF-DC	1,422,628
500 kV Single-Phase, SF_6, GITL, Rigid System	500 kV GITL-R1	1,538,853
500 kV Single-Phase, SF_6, GITL, Flexible System	500 kV GITL-F	1,417,960
500 kV Three-Phase, SF_6, GITL, Rigid System	500 kV GITL-R3	1,338,707
500 kV Resistive Cryogenic Cable	500 kV RC	2,694,461
345 kV Resistive Cryogenic Cable - Rigid System	345 kV RC-R	not costed
230 kV Superconducting Cable	230 kV SC	1,294,881
230 kV Superconducting Cable - Rigid System	230 kV SC-R	2,628,303
300 kV DC Superconducting Cable	300 kV SC-DC	1,695,831
500 kV Aerial/Underground System	500 kV Aerial	667,850

Acronyms used in the table are defined as follows: HPOPT-high pressure oil-filled pipe-type; C-cellulose insulation; PPP-paper polypropylene laminate insulation; F/C-force-cooled; SCOF-self-contained oil-filled; GITL-gas-insulated transmission line; R1- one-phase rigid; F- flexible; R3 - three-phase rigid; RC-resistive cryogenic; SC-superconducting.

3. GENERAL STUDY TECHNIQUES

The designs for the underground systems included in the study were supplied by the EPRI/ERDA-sponsored contractors listed in the Acknowledgments. Most of these programs as well as this study used the English system of units. However, all units have been converted to the SI (International System) in this report. The SI units have been written first, followed by the English unit in parentheses; e.g., 2.54 cm (1 in.). Four systems included in this study were designed in the SI system. They are the 500 kV GITL-F, 230 kV SC, 230 kV SC-R, and the 300 kV SC-DC systems. Consequently, the SI units will be the more accurate values for these systems.

Two units of measurement used in this report, which may not be familiar, are the hectare (ha.), which is a metric value for area equal to 2.471 acres, and the MegaPascal (MPa), which is the SI unit for pressure equal to 145.05 psi.

3.1 Glossary

Terms as used in this report are defined as follows:

Cable - A single physical assembly, which may be single-phase or three-phase.
Line - A complete connection between two terminating points, without parallel conductors, either three-phase AC or two-conductor DC.
Circuit - A complete connection between terminating circuit breakers, made up of either a single line or two lines in parallel.

3. GENERAL STUDY TECHNIQUES (cont'd)

3.2 Economics

3.2.1 General. The main purpose of this study is to estimate the total installed cost of the selected transmission systems including the substations and any required compensation. To make the costs comparable since the study was scheduled for more than one year, all costs are as of January 1, 1976. Yearly costs such as maintenance and energy losses were capitalized using a carrying charge rate of 16.3%. Where necessary to determine present worth of future investments, a 5% inflation rate and a 9¼% interest rate are used. A 40-year life is assumed for all equipment unless otherwise noted.

3.2.2 Losses. The cost of all energy losses is capitalized based on energy costs of 1.76 cents per kilowatthour and a system load factor of 90% for six months and 72% for six months. The load factors are based on anticipated outages of the Energy Park Generation. The 1.76 cents per kilowatthour is based on the cost of energy at transmission voltages on our system and does not include fuel adjustment charges.

A demand charge of $460 per kilowatt is also made on system losses based on a 100% load factor. The $460 charge is based on cost estimates for a combination of oil, coal, and nuclear stations and covers the cost of the generation required to supply the losses.

3. GENERAL STUDY TECHNIQUES

3.2 Economics (cont'd)

3.2.3 Economics of Installation Scheduling. The study assumes that one 1000 MW station will be completed each year for ten consecutive years. This allows the transmission lines to be scheduled as required over the 10-year period. The transmission installation schedule is shown in Table 4-1. In order to compare the costs of the various transmission systems installed in accordance with the installation schedule in 1976 dollars, the present worth of the capital expenditures and their replacements forty years later were computed. The present worth is larger than the 1976 installed cost because two 40-year life cycles were used. This was necessary because the assumed life of a transmission line is forty years and a 10-year difference could exist between the first line and the last line of a system and could invalidate the adjusted figures for comparative purposes. By carrying the comparison out for two life cycles, the value of the cost in the last ten years is negligible and allows a direct comparison between systems. Items required for the initial installation such as real estate, clearing, access roads, and preliminary engineering were included in the initial investment and the remaining dollars allocated in accordance with the installation schedule. The total system cost adjusted as described above is listed in the Cost Summary tables as "Adjusted Grand Total", while the total system cost as of January 1, 1976 is listed as "Grand Total".

3. GENERAL STUDY TECHNIQUES (cont'd)

3.3 Line Route

Energy Park is located in southeastern Pennsylvania on the Susquehanna River approximately 72.4 kilometers (45 miles) south of Harrisburg and 160.9 kilometers (100 miles) north of Washington, DC. The Mid-Site receiving substation, located in Philadelphia, is 106.2 route kilometers (66 miles) north and east of Energy Park. The selected route consists of existing aerial line right-of-way for 96.5 kilometers (60 miles) and Philadelphia city streets for the remaining 9.7 kilometers (6 miles). The line route map, Figure 3-1, locates the path between Energy Park and Mid-Site Substation. The line route includes crossings of the Pennsylvania Turnpike, the Schuylkill Expressway, and the Schuylkill River. For estimating and design purposes, it is assumed that the private right-of-way is newly-purchased and does not contain the aerial transmission lines. The land costs listed in Table 3-1 are used to evaluate real estate costs.

In Philadelphia, it is necessary to occupy city streets to Mid-Site Substation. It is not practical to install more than five enclosures in one street and, therefore, some systems use several routes in the city.

3.4 System Schematic

Each cable system is described by a schematic that specifies the number of lines with location of major associated equipment.

3. GENERAL STUDY TECHNIQUES (cont'd)

3.5 Right-of-Way Width

The underground cable right-of-way width requirements are based on physical and thermal parameters requiring 3 m (10 ft.) and 3.81 m (12.5 ft.) minimum center line trench separation. A 3 m separation is required from the trench center line to the edge of right-of-way. The aerial line width is developed from electrical clearance requirements.

There are no real estate occupancy or rental charges considered for the city street installation.

3.6 Clearing and Access Roads

A high percentage of the route is farmland and is near existing roads. As a result, the cost estimates for clearing and access roads are less than other routes may require.

3.7 Enclosure

The enclosure costs include the outer pipes for the flexible cable systems, the concrete enclosures for the self-contained cables, the total system for spacer-type cables, and the enclosures for all cryogenic systems.

It was estimated that the maximum enclosure length transportable by truck is 18.3 m (60 ft.) which determines the number of enclosure joints per mile. The enclosure installation costs include the materials and labor required for handling, welding, testing, and corrosion protection, return refrigeration pipes, and all associated systems. The material costs are generally those supplied by the designer or manufacturer.

3.7 Enclosures (cont'd)

A major consideration relating to costs is that the HPOPT cable system pipe has greater flexibility than the other rigid type enclosures studied. In addition to conforming to greater trench variations, the pipe can be bent at the construction site to a radius as small as 25 feet. Assuming smooth bends and no sidewall pressure problems during cable installation, this inherent flexibility allows the designer and installer to be less concerned with field adjustments for unexpected obstacles exposed during excavation. Without such field flexibility, unexpected obstacles would significantly delay installation and increase costs. For less flexible systems, the pre-construction, underground explorations must be as thorough and accurate as possible.

3.7.1 Spacer-Type Enclosures and Cable. The costs for handling GITL-type enclosures are greater than HPOPT cable steel pipe due to the spacer-type construction and the more vulnerable aluminum outer material. The enclosure costs for the GITL and the rigid superconducting systems contain all costs for the material and installation of the internal conductor. It should be noted that these integral systems are more rigid than the steel pipe used for HPOPT cable systems and, therefore, the related trench profile must be designed to accommodate the less conforming envelope. The additional cost of trenching is reflected in the estimates for the more rigid systems.

3.7 Enclosures (cont'd)

3.7.2 Laminate-Insulated Cable. The inner enclosure dimensions for laminate-insulated cable installed by pulling into the enclosure requires consideration of damage during installation. For example, the required HPOPT cable steel pipe size is determined by the diameter of the three cables and a related jam ratio. This design consideration reduces the probability of cable damage during installation. In the case of a single cable being pulled into an enclosure, sufficient internal room must be provided to reduce friction to the levels required for long pulls. During installation, there is also danger of damage from small radius pipe bends. Smooth large radius bends reduce this danger.

3.7.3 Enclosure Joints. The HPOPT cable pipe joints are designed with inner welding rings to keep the welding process from forming metallic protrusions that would damage the cable during installation. The welding of all enclosures must be closely inspected; however, the cryogenic systems using helium present a significant problem for both the welding and inspection processes. Helium can escape through what may appear to be good welds by conventional standards. Thus, high cost mass spectrometer, radiograph, and dye penetrant tests are used for helium-associated welds.

3.7.4 Corrosion Protection. A system of pipe coating and cathodic protection is included in the estimates for all enclosures. Although the protection requirements of steel pipe are well known, there is need for more information and experience on the protection of aluminum pipe.

3. GENERAL STUDY TECHNIQUES (cont'd)

3.8 Manholes

Manholes are not required for every cable system. The HPOPT systems are estimated on placement of manholes every 1,760 feet for splicing and oil handling equipment where required. GITL systems, however, do not require manholes since they are a spacer-type system with conductor and enclosure connections at the enclosure joint. Manhole size is determined by splicing and cable pulling requirements. Estimates are based on precast concrete manholes.

3.9 Excavation and Backfill

Estimates for trenching and backfilling are based on over thirty years' experience of installing HPOPT cable in the Philadelphia area. Cost estimates for excavation and backfill include trench survey, removal and replacement of sidewalk or street, trench protection, removal or replacement of all backfills, shoring, pits for cable or envelope splicing and restoration of right-of-way. A 20% to 25% rock content, depending on depth, was used for the estimates.

3.9.1 Typical Trench Cross-Section. For each cable system, there is a typical trench cross-sectional view that specifies the dimensions and type of backfill. The dimensions are based on a 30-inch burial depth, installation considerations and thermal requirements. Systems with self-cooled ratings utilize a well-compacted thermal sand with good heat dissipation characteristics in contact with the enclosure. Only bedding sand is used with the thermally-insulated cryogenic systems.

3.9 Excavation and Backfill (cont'd)

3.9.2 Private Right-of-Way. This type right-of-way offers the most economies for excavation. Rock may be removed by blasting; underground obstructions are minimal, so continuous trenching machines can be used; little removal of excess backfill from the area is required. Access is usually not a problem and, in general, installation progress is much faster than can be accomplished in urban streets. Private right-of-way installations are totally underground in order to present the least visual impact, to protect the cable system, and to allow other usages of the right-of-way, such as agriculture or recreation. After enclosure installation, the right-of-way is appropriately regraded, seeded, and returned to its original condition. In special situations such as water crossings, ravines, and rocky areas, exposed cable system installations, with appropriate protection, can be considered.

3.9.3 Street Installations. Street trench operations are more difficult and costly than on private right-of-way. Road and sidewalk paving must be broken, removed, and replaced. The route is usually obstructed by other utilities. The trench requires shoring and usually must be covered over during non-work hours. In some cases, access to the trench is limited to certain hours of the day. A construction permit is required for each route and every utility affected must be informed.

3.9 Excavation and Backfill (cont'd)

3.9.4 River Crossings. Where the right-of-way crosses the Schuylkill River, the river is approximately 122 m (400 ft.) wide and 4.6 m (15 ft.) deep, with railroads on both banks. Two methods of crossing were studied; a bridge structure spanning both the river and railroads, and a trench under the river bottom and railroads.

The bridge studied was a truss-type structure approximately 305 m (1000 ft.) long with two main supports. The basic structure would cost approximately $3,500,000, and could easily accommodate up to twenty pipe cable lines. Its principal disadvantage was the exposure of all lines to a common accident.

The river bank and bottom in the area of the crossing are rock and the installation assumed a trench cut under the railroads and in the river bed with the pipe anchored at five locations in the river. The estimated labor cost per pipe would be $210,000, assuming that the contractor would install a minimum of six lines at one time.

The trenching installation was selected, since it was more economical and had no visual impact. Other water crossings that would be trenched in below the stream bed are the Wissahickon, Brandywine, and Octoraro Creeks. The additional costs of these crossings would not change the relative comparisons but would alter the per-mile cost. They were not included in the estimate tabulations.

3. GENERAL STUDY TECHNIQUES

3.9 Excavation and Backfill (cont'd)

3.9.5 Highway and Railroad Crossings. The trenching for most highways can be open cut; however, most railroad crossings require boring.

3.10 Cable System Installation

The estimated costs for installing laminate-insulated cable systems are also based on the Philadelphia Electric Company's 30-year history of installing HPOPT cable. This experience with flexible cable systems has been used to project installation estimates for the proposed advanced systems. Cost estimates listed with the cable include installation, splicing, associated insulating medium operations, and grounding-bonding systems. Material costs are primarily those given by the designer or manufacturer with an effort to normalize costs for the advanced systems.

Costs of handling and splicing cryogenic materials are estimated to be significantly more than HPOPT or self-contained cable. Many installation questions will not be answered until the systems are available and the installation is actually experienced. With this thought, projections of the installation costs for future systems were made from a known reference point. The costs for the metallurgical testing and clean room procedures required for the cryogenic systems are listed with the enclosure estimate.

3. GENERAL STUDY TECHNIQUES

3.10 Cable System Installation (cont'd)

3.10.1 Cable Pulling Lengths. The average length between splicing locations for the eight tape insulated flexible cable systems is assumed to be 536.5 m (1760 ft.). This assumption considers the following factors.

- The Pennsylvania Department of Transportation limits truck loads to 2.44 m (8 ft.) wide, 4.1 m (13.5 ft.) high, and 33,244 kg (73,290 lb.) on five axles. However, special permits can be obtained for wider loads and load widths of 3 m (10 ft.) are not uncommon.
- The cable manufacturing facility will be remote from the right-of-way and thus cable transportation will be required over public conveyance.
- The design of the cryogenic cables would allow pulling lengths similar to those of existing cable systems.

3.10.2 Shipping Reels. The design of the reel used for cable delivery is based on the minimum bending radius required to avoid cable damage. For HPOPT and SCOF cables, the minimum bending radius is considered to be 10 to 12 times the cable diameter. The superconducting cable bending limits are less specific; however, a multiple of 12 may be required. The following tabulation illustrates the capacity of a reel 3.8 m (12.5 ft.) high by 2.44 m (8 ft.) wide with a 2.74 m (9 ft.) drum diameter.

3. GENERAL STUDY TECHNIQUES

3.10 Cable System Installation

3.10.2 Shipping Reels (cont'd)

Cable System	Cable Diameter cm	Cable Diameter in.	Factor for Minimum Bending Radius	Minimum Reel Drum Diameter m	Minimum Reel Drum Diameter ft.	Cable Length on 2.74 m (9 ft.) Drum Diameter m	Cable Length on 2.74 m (9 ft.) Drum Diameter ft.
500 kV HPOPT-C	12.01	4.73	10	2.15	(7.05)	674.5	(2213)
500 kV HPOPT-PPP	10.21	4.02	10	2.04	(6.7)	933.6	(3063)
765 kV HPOPT-PPP	12.50	4.92	10	2.5	(8.2)	623.3	(2045)
500 kV SCOF-AC-PPP	13.4	5.27	10	2.68	(8.78)	543.2	(1782)
600 kV SCOF-DC-C	12.4	4.89	10	2.48	(8.15)	631.2	(2071)
500 kV RC-C	13.8	5.44	10	2.76	(9.07)	509.9	(1673)
230 kV SC	14.3	5.6	12	3.41	(11.2)	*	*
300 kV SC-DC	9.69	3.8	12	2.32	(7.6)	1044.9	(3428)

* As indicated, the 230 kV SC system requires a 3.41 m (11.2 ft.) diameter drum which could seriously reduce pulling lengths. A cable length of 640 meters (2100 ft.) is possible on a reel 4.57 m (15 ft.) high by 3 m (10 ft.) wide with a drum diameter of 3.41 m (11.2 ft.). However, special highway permits would be required.

3. GENERAL STUDY TECHNIQUES

3.10 Cable System Installation (cont'd)

3.10.3 Cable Installation. There are two types of installations involved with these cable pulls. All but the SCOF systems utilize enclosures. The SCOF cables are laid in a trench on private right-of-way and pulled on rollers into the excavation in city streets. The pipe installations are usually limited by the maximum tension or sidewall pressure that the cable can endure during cable pulls. In a straight installation, the HPOPT cables can be pulled more than 914.4 m (3000 ft.). However, the pipe bends required in practical installations reduce the length that can be pulled. Two recent 230 kV HPOPT cable installations in streets, similar to but perhaps not directly comparable to the Mid-Site area, averaged approximately 580 m (1900 ft.) cable pulling lengths. Cable suppliers providing data for this report indicate that 762 m (2500 ft.) pulls would be made with the 500 kV HPOPT cable.

3.10.4 Cost Sensitivity. Selection of three splice locations per mile for each of the cable systems recognizes that optimization of cable lengths would be possible with a defined route. However, based on the HPOPT costs, the effect of changing the cable pulling lengths and splicing locations 20% would change the system costs by less than 1% of the grand total.

3. GENERAL STUDY TECHNIQUES

3.11 Terminations

Estimates for installing terminations include all material and labor required from the top of the termination to the enclosure and include such equipment peculiar to terminating the cable such as the HPOPT trifurcator and all supporting structures.

3.12 Cable System Pressurizing and Refrigeration Plants

Each type of cable system contains an insulating, pressurizing, and/or cooling medium; oil in the HPOPT and SCOF systems, SF_6 gas in the GITL systems, liquid nitrogen in the resistive cryogenic systems, and helium in the superconducting systems. The costs of the pressurizing and cooling systems for the resistive cryogenic and superconducting systems are included in Chapter 7, Refrigeration and Design.

3.12.1 Distribution Power Supply. The costs for the electric distribution supply system to the refrigeration plants of both force-cooled HPOPT and cryogenic type cable systems are included with the refrigeration plant costs. The remote plant locations, the reliable distribution supply lines required, and the significant load, 46.5 MW maximum, required that both the area distribution and transmission systems be analyzed in order to estimate electric supply costs.

3.13 Monitoring Systems

All of the cable systems require some form of monitoring to warn of malfunctions. The HPOPT and SCOF cable system pressurizing plants have alarms that are included in the cost of the plants.

3. GENERAL STUDY TECHNIQUES

3.13 Monitoring Systems (cont'd)

The GITL systems have more elaborate monitoring requiring a signal cable for the entire length of each line. Stop joints, every .8 km (0.5 mi.), are used to isolate the system in case of a leak. Each section contains valves and piping in a handhole to fill the section with SF_6 gas and remove test samples. High and low pressure relays activate alarms at remote monitoring stations.

The cryogenic systems also require an extensive monitoring system. This design employs a signal cable for the entire length of the line. Thermally-activated switches on the enclosure of each vacuum section signal a temperature drop, associated with a loss of vacuum, to a remote monitoring station. Thermocouples are also installed on the enclosure near the thermal switches to confirm alarm signals and provide periodic data on the efficiency of the insulation. The resistive cryogenic cable monitoring system is similar to the superconducting monitoring system except that thermal switches and thermocouples are located every 305 m (1000 ft.)

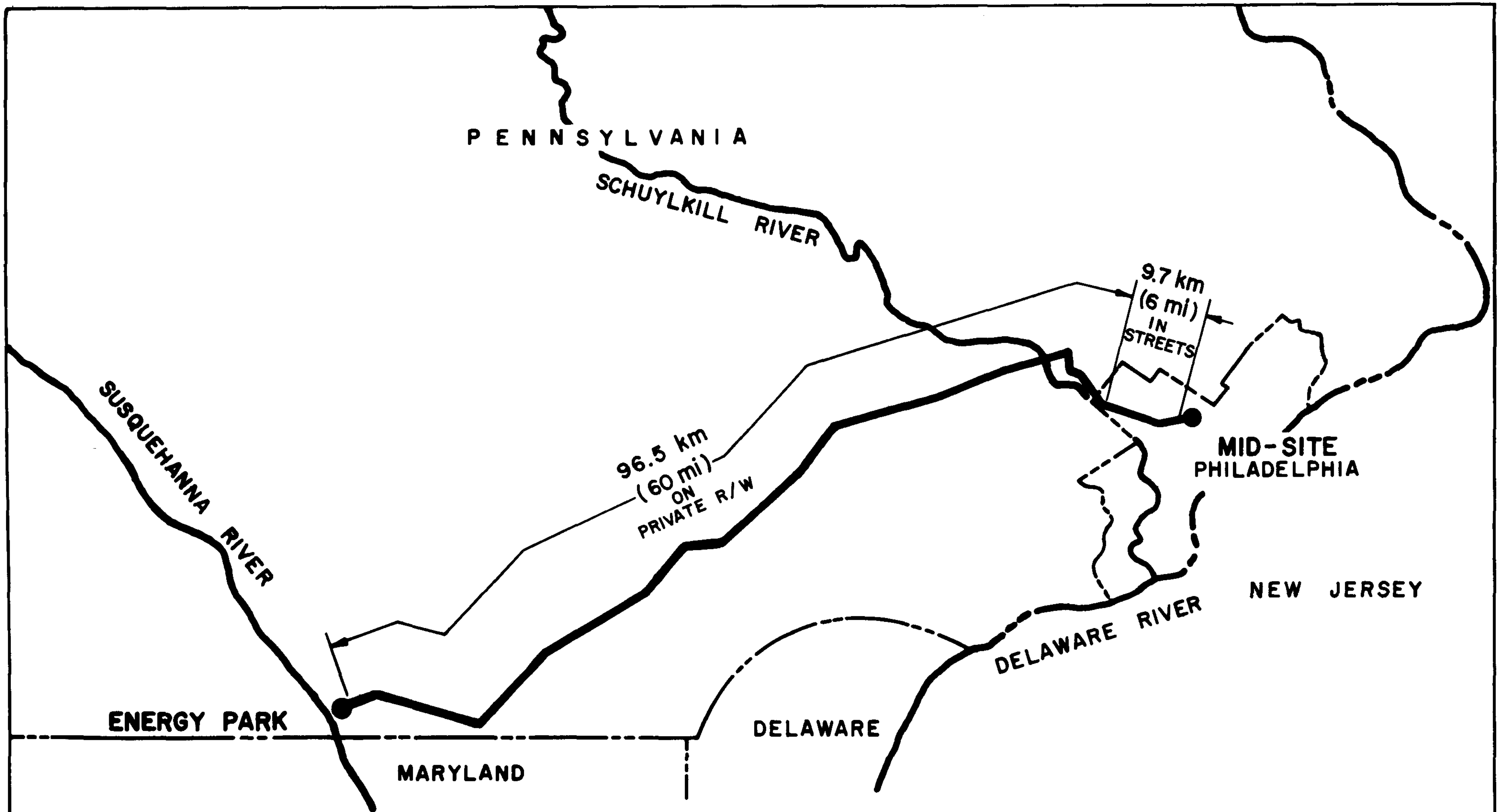
3.14 Maintenance

The capitalized cost of maintenance is included for all systems studied. It is based on our cost to maintain existing HPOPT cable systems and our private right-of-way. The maintenance costs for the other systems were extrapolated from the HPOPT cable costs with the assumption that no extraordinary maintenance problems would occur.

3. GENERAL STUDY TECHNIQUES (cont'd)

3.15 Engineering

The estimated costs for engineering are projected from experience with HPOPT cable systems. Consideration is made for length and end points.



ROUTE MAP

ENERGY PARK TO MID-SITE

106.2 km (66 mi)

FIG. 3-1

Table 3-1

Real Estate Costs

Right-of-Way Costs

Description	Type	Length	Estimated Cost
Energy Park to Lancaster County Line	Private	14 km (9 mi.)	2,020 $/ha. (5,000 $/ac)
Lancaster County Line to Planebrook area	Private	50 km (31 mi.)	4,040 $/ha. (10,000 $/ac)
Planebrook area to Upper Merion area	Private	14 km (9 mi.)	5,700 $/ha. (14,000 $/ac)
Upper Merion area to Roxborough area	Private	18 km (11 mi.)	20,200 $/ha. (50,000 $/ac)
Roxborough area to Mid-Site Substation	City Streets	10 km (6 mi.)	

Substation Land Costs

	Energy Park		2,020 $/ha. (5000 $/ac)
	Mid-Site		2,424 $/ha. (60,000 $/ac)

4. SYSTEM PLANNING

4.1 Introduction

Criteria were developed for the 10,000 MW Energy Park transmission system so that any of the alternate plans would meet normal utility reliability and operating requirements. These criteria were designed to be neither preferential nor prejudicial to any given type transmission system.

The planning of the Energy Park transmission was made as realistic as possible by using load flow, transient stability, and short circuit models based on representative system configurations of the Pennsylvania-New Jersey-Maryland (PJM) Interconnection for the mid-1990's period. All of the various designs delivered the entire output of Energy Park to a substation (called Mid-Site) in Philadelphia. At Mid-Site, over half the delivered power was stepped down to 230 kV to supply the Philadelphia load area. The remainder was transmitted into the PJM 500 kV network over two 500 kV aerial lines from Mid-Site to the Whitpain Substation, located northwest of Philadelphia.

Two alternate plans were developed to connect the Energy Park to the system. The first plan consisted of a radial connection from Energy Park to Mid-Site; the second plan included, in addition to the above, a tieline of approximately 1 km from Energy Park to the PJM 500 kV grid. The connection was made to a 4000 MW generation complex on the lower Susquehanna River; half of this capacity is now in service as the Peach Bottom #2 and #3 generating stations.

4.2 Methodology

The planning and testing of the various transmission systems were generally performed using the Philadelphia Electric Company's AC Load Flow, Transient Stability, and Short Circuit digital computer programs.[1,2,3] These programs are widely recognized and are used by over 140 utilities and educational and governmental institutions. Manual calculations were also used to determine transient stability limits utilizing the power angle method.[4] These stability limits were then confirmed for several cases by using the Transient Stability computer program.

4.3 Criteria

The planning criteria were based as nearly as possible on the reliability principles used by Philadelphia Electric Company. Some criteria had to be developed especially for the unique characteristics of a large futuristic radial energy park. Special consideration was given to anticipated equipment developments and to the magnitude of potential capacity loss by concentrating 10,000 MW of generation at one location with only radial ties. However, there is sufficient engineering and cost data contained in this report to determine the effects of variations in the design criteria.

4.3.1 Transmission Loading. The various Energy Park transmission systems were designed to transmit the 10,000 MW of generation to the Mid-Site Substation while meeting the imposed circuit loading criteria. The criteria were based on the concept

4. SYSTEM PLANNING

4.3 Criteria

4.3.1 Transmission Loading (cont'd)

that no more than 2500 MW of Energy Park generation would have to be tripped for any single contingency. The 2500 MW value would be approximately the maximum generation loss that could be tolerated without extensive intra- and inter-regional transmission reinforcements (there is further expansion of this concept in Appendix I). Separate consideration was given to the completed Energy Park project and to the intermediate construction stages.

4.3.1.1 Completed Energy Park. Sufficient circuits were provided for the Energy Park so that:

- Any single circuit outage would not cause normal overloads at full Energy Park generation (10,000 MW) with all other circuits available (first contingency).
- The outage of any circuit while another circuit was out for maintenance would not cause overloads above the four-hour emergency rating at 75% Energy Park generation, 7,500 MW (second contingency). (This effectively precludes all two-circuit systems. See further discussion of this aspect in Appendix I.) The system would be designed so that a line out for maintenance would be available for service within twenty-four hours.

4. SYSTEM PLANNING

4.3 Criteria

4.3.1 Transmission Loading

4.3.1.1 Completed Energy Park (cont'd)

The circuit ratings that were needed to meet the preceding criteria were used to determine the size and number of circuits for each of the cable systems studied. This data is listed in the table below.

No. of Circuits Used**	Normal Conditions Continuous Duty MVA	1st Contingency Continuous Duty MVA	2nd Contingency 4-Hour Duty MVA
2	5,000	10,000	*
3	3,333	5,000	7,500
4	2,500	3,333	3,750
5	2,000	2,500	2,500
6	1,667	2,000	1,875
7	1,429	1,667	1,500
8	1,250	1,429	1,250
9	1,111	1,250	1,071

* Cannot meet requirements

** In some cases two cables were required per circuit to achieve ratings.

4. SYSTEM PLANNING

4.3 Criteria

4.3.1 Transmission Loading (cont'd)

4.3.1.2 Intermediate Energy Park. Modified criteria were apecified for the ten-year development stage of Energy Park and were used primarily to determine the timing of circuit installations. For 1000 to 5000 MW of generation installed, there must be sufficient circuits to satisfy the following conditions:

- All circuits in service - circuits shall carry full generation indefinitely.
- Failure of one circuit - remaining circuits shall carry the installed generating capacity minus 2,500 MW indefinitely.
- If a circuit is out for maintenance, generation can be reduced accordingly.

For 6,000-10,000 MW of generation installed, there must be sufficient circuits to satisfy the same conditions as for the completed Energy Park. Table 4-1 details the installation schedule of the various transmission types that would be required to meet the preceding criteria.

Table 4-1

Line Installation Schedule

Year of Installation	Total Mw of Generation Installed	Number of Lines Installed 16 Lines	12 Lines	9 Lines	8 Lines (A)*	8 Lines (B)
1	1,000	2	2	1	2	1
2	2,000	3	3	2	2	2
3	3,000	5	4	3	4	3
4	4,000	6	5	4	4	4
5	5,000	8	6	5	4	4
6	6,000	10	8	6	6	6
7	7,000	12	9	7	6	7
8	8,000	13	10	8	8	8
9	9,000	15	11	9	8	8
10	10,000	16	12	9	8	8

16 line system - 500 kV HPOPT Cellulose - Insulated Cable

12 line system - 500 kV HPOPT PPP - Insulated Cable

9 line system - 765 kV HPOPT PPP - Insulated Cable

8 line system (A) - 500 kV Force-Cooled HPOPT PPP - Insulated Cable

8 line system (B) - 500 kV AC Self-Contained Oil-Filled Cable

* Lines are installed in pairs

(Cont'd)

Table 4-1 (Cont'd)

Year of Installation	Total Mw of Generation Installed	Number of Lines Installed			
		6 Lines*	5 Lines	4 Lines	3 Lines
1	1,000	2	1	1	1
2	2,000	2	1	1	1
3	3,000	2	2	2	2
4	4,000	2	2	2	2
5	5,000	4	3	2	2
6	6,000	4	4	3	3
7	7,000	6	4	3	3
8	8,000	6	5	4	3
9	9,000	6	5	4	3
10	10,000	6	5	4	3

6 line system - 765 kv Force-Cooled HPOPT PPP -Insulated System

5 line system - 500 kv Single-Phase SF_6, GITL, Flexible System
500 kv Three-Phase SF_6, GITL, Rigid System
500 kv Aerial/Underground System

4 line system - 500 kv Resistive Cryogenic Cable
600 kv DC Self-Contained Oil-Filled Cable

3 line system - 500 kv Single-Phase SF_6, GITL, Rigid System
230 kv Superconducting Cable
230 kv Superconducting Cable, Rigid System
300 kv DC Superconducting Cable

* Lines are installed in pairs

4. SYSTEM PLANNING

4.3 Criteria (cont'd)

4.3.2 Transient Stability. The various transmission systems were designed to withstand, without generator instability, a three-phase fault at Energy Park on any circuit termination with a primary protection system clearing time of 2.75 cycles. An exception was made for systems with excessive short circuit duties which required special sequential relaying. The special relaying, which sectionalized the bus to reduce the short circuit duties on the circuit breakers, increased the primary protection clearing time by 0.5 cycle to 3.25 cycles. The clearing times were based on a primary breaker clearing time of 2.25 cycles with an additional 0.5 cycle inserted to increase stability margins to cover system conditions - e.g., lighter load levels, back-up fault clearing, etc. - which could not be considered in this study. It is anticipated that circuit breakers of this capability would be available by the 1990's, the time period assumed for the study. The Transient Stability Program calculations that were performed for two of the transmission systems showed that the system remained stable for a three-phase fault with a single-pole stuck breaker with primary clearing at 2.25 cycles and back-up clearing at 7.0 cycles. These results indicated that the additional 0.5 cycle in the primary protection system clearing time was sufficient to maintain stability.

Power angle curves have been drawn for each cable system to show the critical clearing time for the limiting contingency. These curves show the electrical output versus the machine angle

4.3.2 Transient Stability (cont'd)

of the Energy Park generation for a three-phase fault at the Energy Park bus. For the generators to remain stable, the decelerating area, which follows the clearing of the fault, must exceed the accelerating area, which occurs while the fault is on. When the Energy Park units were found initially unstable following a fault, sufficient series capacitors were added to maintain stability or, if the fault was the second contingency, two generators (2000 MW) were tripped and series capacitors, if still necessary, were added to allow the system to remain stable. If the two generators were tripped, the remaining Energy Park generation was reduced by a total of 500 MW to 7500 MW to meet the circuit loading criteria. Other stabilizing techniques, such as fast valving, dynamic braking, etc., could possibly be used to improve stability; however, it was decided that series capacitors would be technically and economically more feasible to evaluate.

Generator swing curves, which plot the machine angle versus time during and following the fault, are shown for several of the transmission systems to indicate the effect of the fault on the surrounding systems.

The ten 1000 MW generators at Energy Park consist of five coal-fueled steam units and five nuclear-fueled steam units. The generator data that was used for the transient stability

4.3.2 Transient Stability (cont'd)

and short circuit analyses was taken from two generators currently in the PJM system. The model for the coal-fueled unit was the 850 MW Keystone #1 generator. The model for the nuclear-fueled station was the 1051 MW Peach Bottom #2 generator. Adjustments were made in the data to compensate for the difference between these generators and the 1000 MW Energy Park generators.

4.3.3 Compensation. Reactive compensation was applied as required to the various Energy Park transmission systems in the form of series capacitors, series reactors, and shunt reactors. These compensation devices are detailed in Table 4-2 and were required in order to meet one or more of the following criteria:

- Energy Park generation would not normally be required to operate at a leading power factor; that is, in an unaerexcited condition.
- Cable MW capacities would not be limited by charging current.
- Transient stability would be maintained.

Table 4-2

Line Compensation

Cable System	Radial System: Series Ohms/Line	Radial System: Series Current Amperes/Line	Radial System: Shunt MVAR/Line	Network System: Series Ohms/Line	Network System: Series Current Amperes/Line	Network System: Shunt MVAR/Line
500 Kv HPOPT Cellulose-Insulated Cable	0		2160	22.0	830	2160
500 Kv HPOPT PPP-Insulated Cable	0		1968	13.75	1154	1968
765 Kv HPOPT PPP-Insulated Cable	0		3504	18.56	943	3504
500 Kv Force-Cooled HPOPT PPP-Insulated Cable	0		1968	3.45	1650	1968
765 Kv Force-Cooled HPOPT PPP-Insulated Cable	0		3504	6.39	1509	3504
500 Kv AC Self-Contained Oil-Filled Cable	0		2895	12.65	1650	2895
600 Kv DC Self-Contained Oil-Filled Cable	0		0	0		0
500 Kv Single-Phase SF_6, GITL, Rigid System	0		380	3.75	8660	130
500 Kv Single-Phase SF_6, GITL, Flexible System	0		0	4.25	2887	0
500 Kv Three-Phase SF_6, GITL, Rigid System	0		0	4.0	2887	0
500 Kv Resistive Cryogenic Cable	0		2695	-4.0	4330	2695
230 Kv Superconducting Cable	-0.29	18827	0	0		0
230 Kv Superconducting Cable, Rigid System	-10.92	18827	0	-10.48	18827	0
300 Kv DC Superconducting Cable	0		0	0		0
500 Kv Aerial/Underground System	-7.5	2887	0	-20.2	2887	0

Note: Positive ohmic values refer to reactors.
Negative ohmic values refer to capacitors.
Current refers to first or second contingency loading.

4.3.3 Compensation (cont'd)

- The network plan for the Energy Park transmission would not change the normal power flow conditions in the surrounding PJM network from those in the radial Energy Park case.

Shunt reactors were connected at the Energy Park and Mid-Site substations, and in some instances, at intermediate substations along the cable route to meet the first two of the above criteria. These reactors were used to adjust the power factor of the Energy Park generators and to prevent cable limitations due to charging currents. The series capacitors were used in some systems to meet the transient stability criteria by reducing the net impedance of the cable system and were used in one cable system to maintain a 10,000 MW flow on the cables in the network configuration. Currently, there are technical problems, one being resonance, associated with using series capacitors to compensate long transmission lines. It is beyond the scope of this project to investigate these problems and we assume that research efforts will resolve these problems by the 1990's. The series reactors, which were necessary only in the network systems, were used to maintain a 10,000 MW flow on the cable systems. It is likely that by the 1990's there will be other devices available to achieve this control.

4.3 Criteria (cont'd)

4.3.4 Short Circuit Duty. Review of current research efforts revealed that circuit breakers with interrupting capacities of 90,000 A are feasible for the mid-1990's period. In this study, when breaker duties for any cable system exceed this value, special sequential relaying techniques, discussed in Chapter 5.4.2, were used to bring the duties on individual breakers within limits. As noted, this effectively increased total fault clearing time. Table 4-3 details the short circuit duties measured at the Energy Park and Mid-Site buses for the various transmission system designs.

Circuit breakers are rated on the basis of symmetrical current interrupting capability; the asymmetrical current capability is dependent upon the breaker clearing time, which determines the fault clearing time. With a fault clearing time of 2.25 cycles, the asymmetrical current interrupting capability would be between 30% and 40% above the symmetrical current capability.

Short circuit impedance diagrams are shown for both the radial and network configurations for each cable system. These diagrams show the effective impedance of the cable system and the surrounding transmission network from the Energy Park generators to the infinite bus, which represents all of the generators in the system.

4.4 Circuit Analysis

Specific system planning considerations which apply to the separate types of transmission are discussed under their respective headings.

Table 4-3

Short Circuit Fault Duties

	Fault Location	Radial System Fault MVA	Radial System Fault Current	Network System Fault MVA	Network System Fault Current
500 kV HPOPT-C	Energy Park 500 kV	52,500 mva	60,600 amps	80,200 mva	92,600 amps
16 Lines	Mid-Site 500	52,400	60,500	59,400	68,600
8 Circuits	Mid-Site 230	40,400	101,400	41,100	103,200
500 kV HPOPT-PPP	Energy Park 500 kV	52,300 mva	60,400 amps	80,400 mva	92,800 amps
12 Lines	Mid-Site 500	52,300	60,400	59,500	68,800
6 Circuits	Mid-Site 230	41,900	105 300	43,200	108,400
765 kV HPOPT-PPP	Energy Park 765 kV	50,000 mva	37,700 amps	59,100 mva	44,600 amps
9 Lines	Mid-Site 765 kV	42,200	31,800	52,700	39,800
9 Circuits	Mid-Site 500 kV	38,000	43,900	38,600	44,600
	Mid-Site 230 kV	40,300	101,000	40,600	101,900
500 kV HPOPT-F/C	Energy Park 500 kV	50,500 mva	58,300 amps	80,200 mva	92,600 amps
8 Lines	Mid-Site 500	50,400	58,200	59,300	68,500
8 Circuits	Mid-Site 230	40,000	100,400	41,500	104,200
765 kV HPOPT-F/C	Energy Park 765 kV	49,300 mva	37,200 amps	59,300 mva	44,800 amps
6 Lines	Mid-Site 765	48,300	36,500	52,900	39,900
6 Circuits	Mid-Site 500	37,700	43,500	38,700	44,700
	Mid-Site 230	40,300	101,200	41,000	102,900
500 kV SCOF-AC	Energy Park 500 kV	53,000 mva	61,200 amps	80,200 mva	92,600 amps
8 Lines	Mid-Site 500	53,000	61,200	59,300	68,500
8 Circuits	Mid-Site 230	41,000	102,900	41,500	104,200

Table 4-3 (Cont'd)

		Radial System		Network System	
	Fault Location	Fault MVA	Fault Current	Fault MVA	Fault Current
500 kV GITL-R1	Energy Park 500 kV	52,100 mva	60 200 amps	80,100 mva	92,500 amps
3 Lines	Mid-Site 500	52,000	60,000	59,200	68,400
3 Circuits	Mid-Site 230	40,300	101,200	41,100	103,200
500 kV GITL-F	Energy Park 500 kV	51,300 mva	59,200 amps	80,100 mva	92,500 amps
5 Lines	Mid-Site 500	51,100	59,000	59,200	68,400
5 Circuits	Mid-Site 230	39,900	100,200	41,100	103,200
500 kV GITL-R3	Energy Park 500 kV	51,100 mva	59,000 amps	80,100 mva	92,500 amps
5 Lines	Mid-Site 500	51,000	59,900	59,100	68,200
5 Circuits	Mid-Site 230	39,900	100,200	41,000	103,000
500 kV RC	Energy Park 500 kV	47,900 mva	55,300 amps	80,200 mva	92,600 amps
4 Lines	Mid-Site 500	47,700	55,100	59,100	68,200
4 Circuits	Mid-Site 230	39,000	97,800	41,400	103,900
230 kV SC	Energy Park 230 kV	48,800 mva	122,500 amps	54,700 mva	137,300 amps
3 Lines	Mid-Site 230	48,500	121,700	49,800	124,800
3 Circuits	Mid-Site 500	32,200	37,200	32,300	37,300
230 kV SC-R	Energy Park 230 kV	49,500 mva	124,300 amps	54,200 mva	136,100 amps
3 Lines	Mid-Site 230	49,000	123,000	48,800	122,500
3 Circuits	Mid-Site 500	32,400	37,400	32,200	37,200
500 kV Aerial	Energy Park 500 kV	45,800 mva	52,900 amps	80,200 mva	92,600 amps
5 Lines	Mid-Site 500	45,600	52,700	59,300	68,500
5 Circuits	Mid-Site 230	38,200	95,900	41,500	104,200

4.4 Circuit Analysis (cont'd)

4.4.1 High-Pressure Oil-Filled Pipe-Type Cable (HPOPT).

4.4.1.1 General. The five types of HPOPT cable systems required from six to sixteen lines to provide the capacity to carry 10,000 MW from the Energy Park to the Mid-Site Substation. The number of circuits required to meet the loading criteria was determined from the ampacity calculations, which are discussed in Chapter 6. At the Mid-Site Substation, four transformers were used to provide power to the 230 kV network in the Philadelphia load area and two 500 kV aerial lines supplied power to the PJM 500 kV network. In the case of the two 765 kV HPOPT cable systems, two 765/500 kV transformers were needed to supply the power to the 500 kV lines.

The load flow analysis showed that all five of these cable systems required shunt reactive compensation to allow the Energy Park generators to operate in the over-excited range and to prevent the charging current from limiting the MW capacities. As a result, compensation was provided for the total line charging current in each of the five cases. This was done by placing shunt reactors at intermediate points on each line and at the endpoint substations. The calculations are discussed in Chapter 6 and the amounts of compensation are shown in Table 4-2. The shunt compensation requirements remained the same for both the radial and network systems. However, series

4. SYSTEM PLANNING

4.4 Circuit Analysis

4.4.1 High-Pressure Oil-Filled Pipe-Type Cable (HPOPT).

4.4.1.1 General (cont'd)

compensation provided by reactors was only required in the network system of each of the HPOPT cables. These reactors were necessary to limit the normal total flow to 10,000 MW. Without the reactors, the equivalent impedance of the cables was insufficient to prevent the network power from flowing into the Energy Park transmission.

Power angle stability calculations for the five HPOPT cable systems showed that the system would have no stability problems. The large number of parallel lines resulted in a stable system for two reasons. First, the combined impedance of the cables resulted in a low equivalent impedance between the generation and the load. Second, the large number of lines allowed one circuit to be lost without significantly affecting the impedance between the generation and the load.

The short circuit duties for three-phase faults at the Energy Park and Mid-Site buses are shown in Table 4-3. The larger fault duties found for the network system as compared to the radial system were caused by

4.4 Circuit Analysis

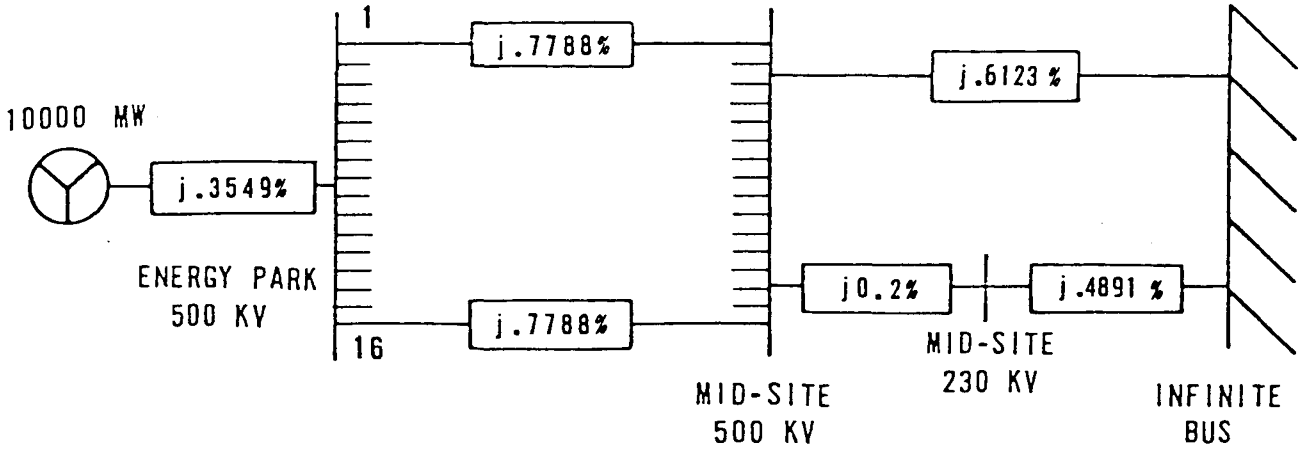
4.4.1 High-Pressure Oil-Filled Pipe-Type Cable (HPOPT)

4.4.1.1 General (cont'd)

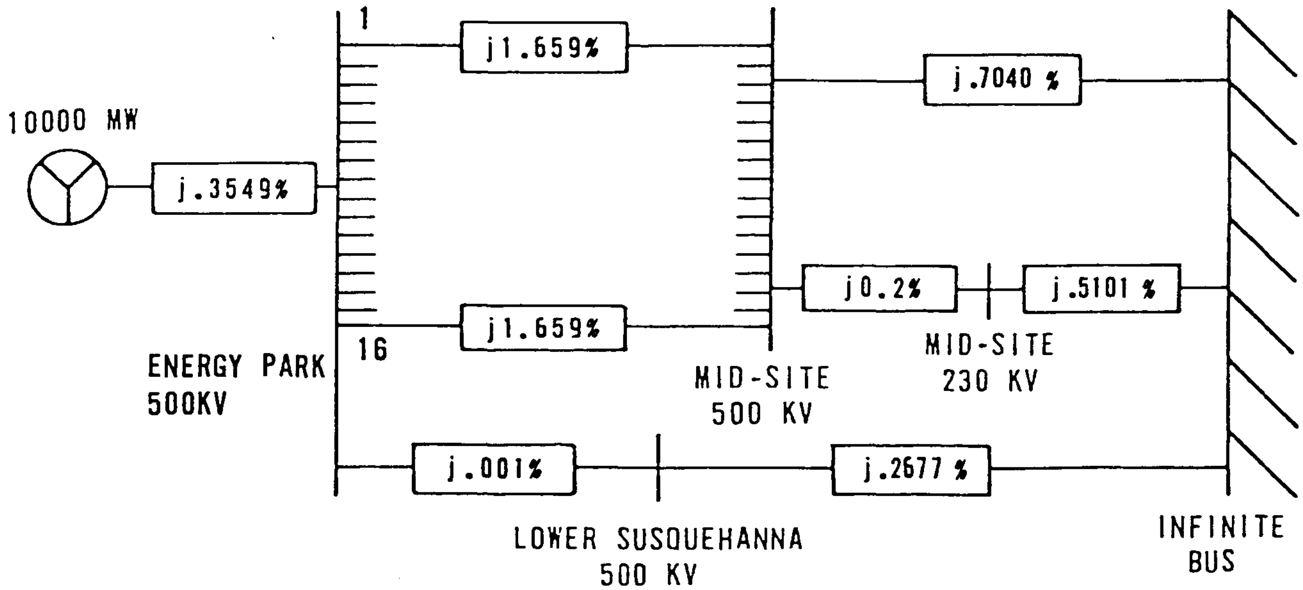
additional sources of generation in the PJM 500 kV network. The short circuit impedance diagrams for the five HPOPT systems are shown in Figures 4-1 through 4-5.

4.4.1.2 500 kV HPOPT Cellulose-Insulated Cables

- Compensation. This cable required eight circuits, with two lines per circuit, to meet the transmission loading criteria. The shunt compensation of 2160 MVAR per line was divided into five sections, with one 540 MVAR reactor at each of three intermediate stations and one 270 MVAR reactor at each line endpoint. For series compensation, a 22-ohm reactor was connected in each line at the Energy Park substation.
- Transient Stability. The first contingency, which is the loss of one circuit due to a three-phase fault with delayed clearing, was the most critical condition for both the radial and network systems. Critical clearing times of 7.2 and 11.9 cycles, for the radial and network systems respectively, indicated that the system would remain stable for a three-phase fault. The power angle curve for the radial system is shown in Figure 4-6.



RADIAL SYSTEM

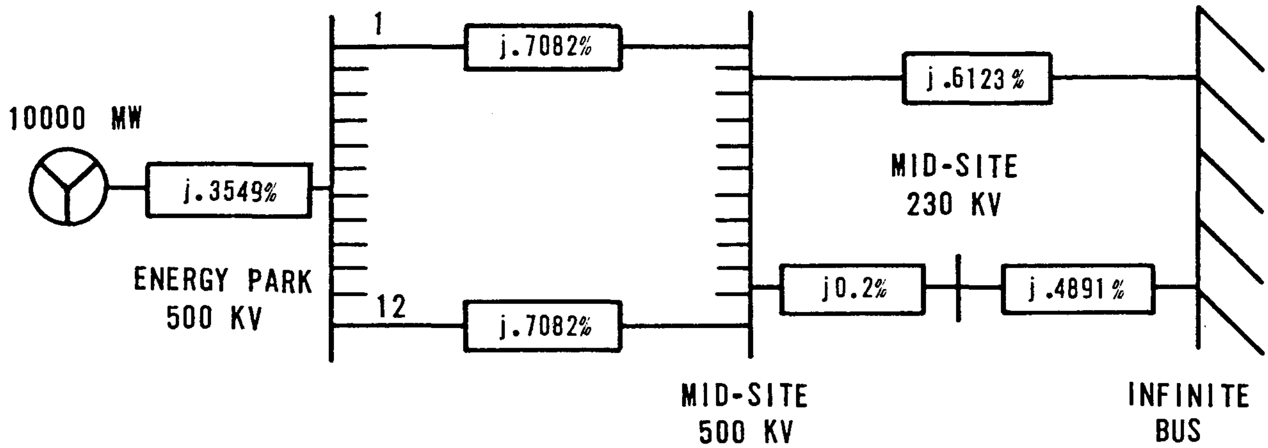


NETWORK SYSTEM

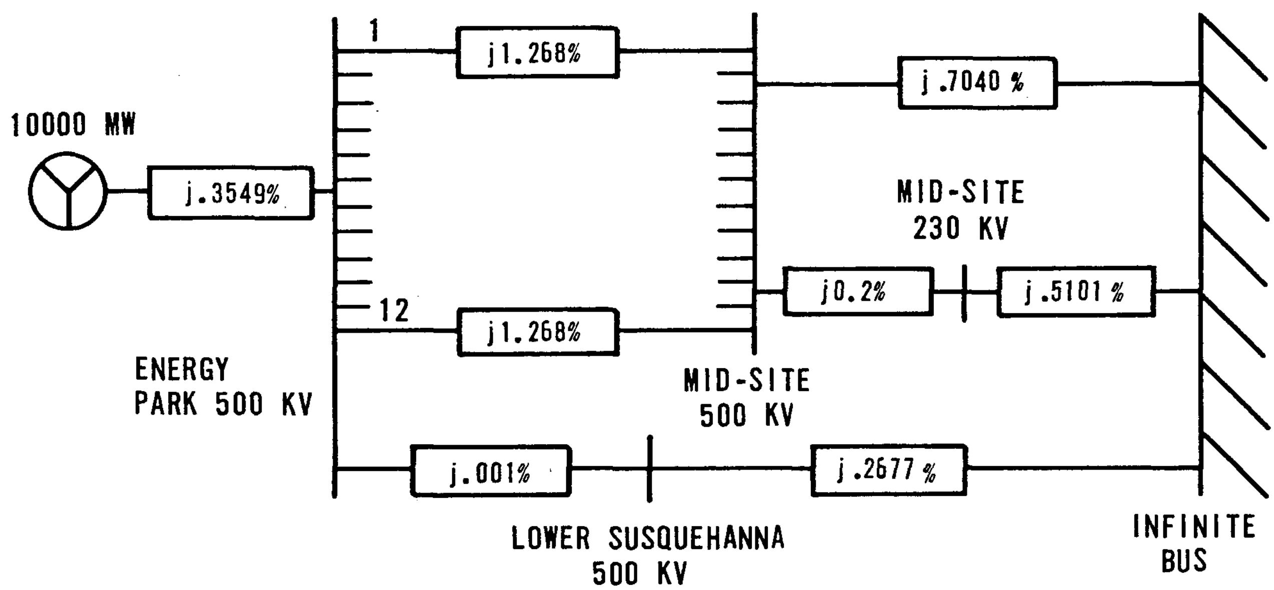
NOTE: IMPEDANCES ARE IN PERCENT ON A 100 MVA BASE

SHORT CIRCUIT DIAGRAMS
500 KV HPOPT CELLULOSE-INSULATED CABLE
16 LINES IN PARALLEL

FIG. 4-1



RADIAL SYSTEM

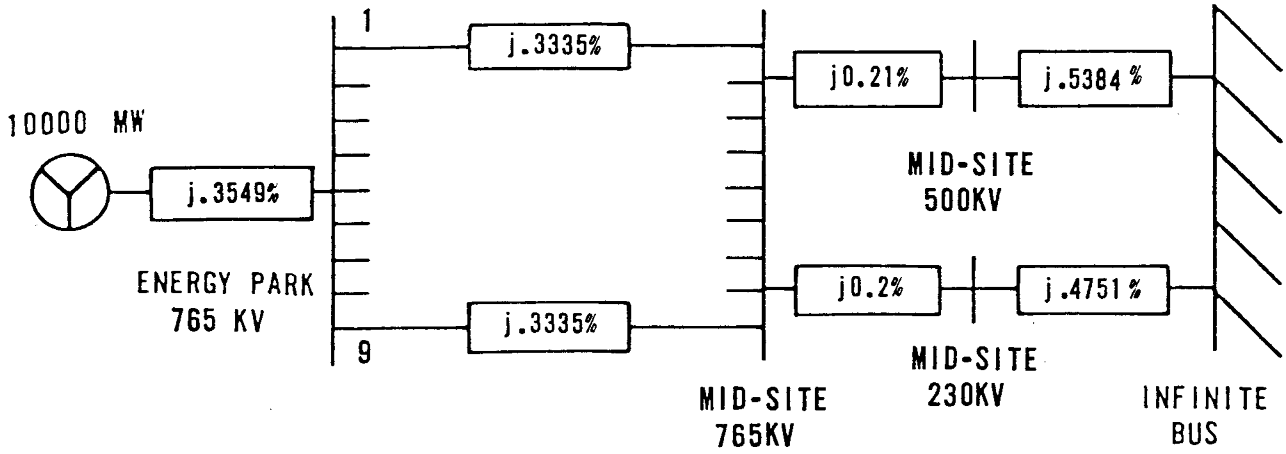


NETWORK SYSTEM

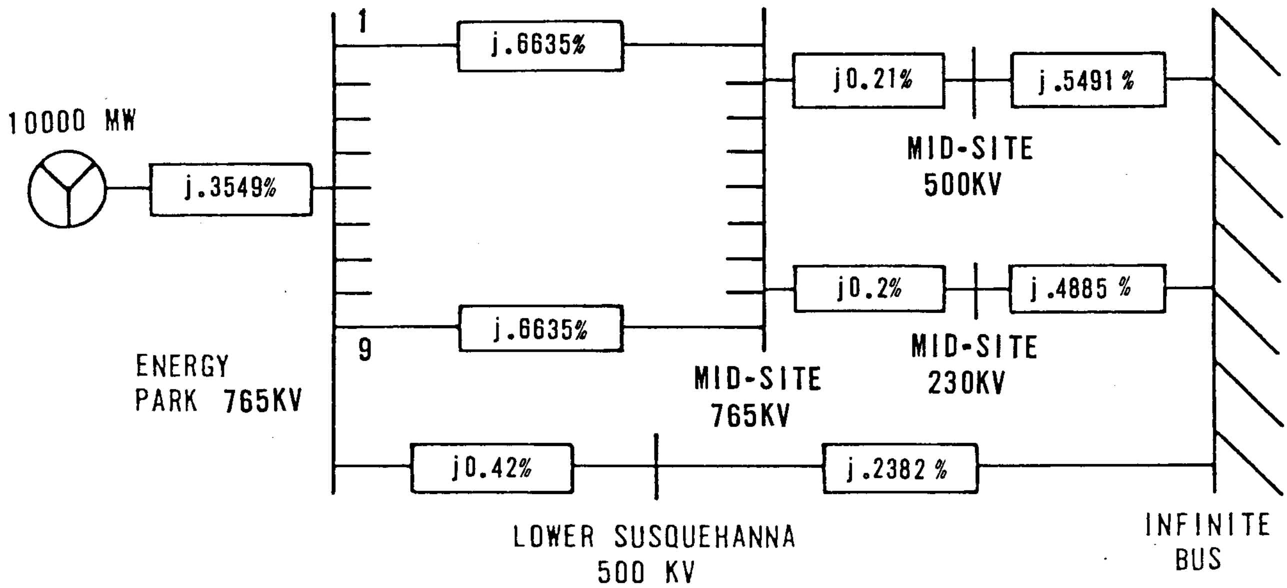
NOTE: IMPEDANCES ARE IN PERCENT ON A 100 MVA BASE

SHORT CIRCUIT DIAGRAMS
500 KV HPOPT PPP-INSULATED CABLE
12 LINES IN PARALLEL

FIG. 4-2



RADIAL SYSTEM



NETWORK SYSTEM

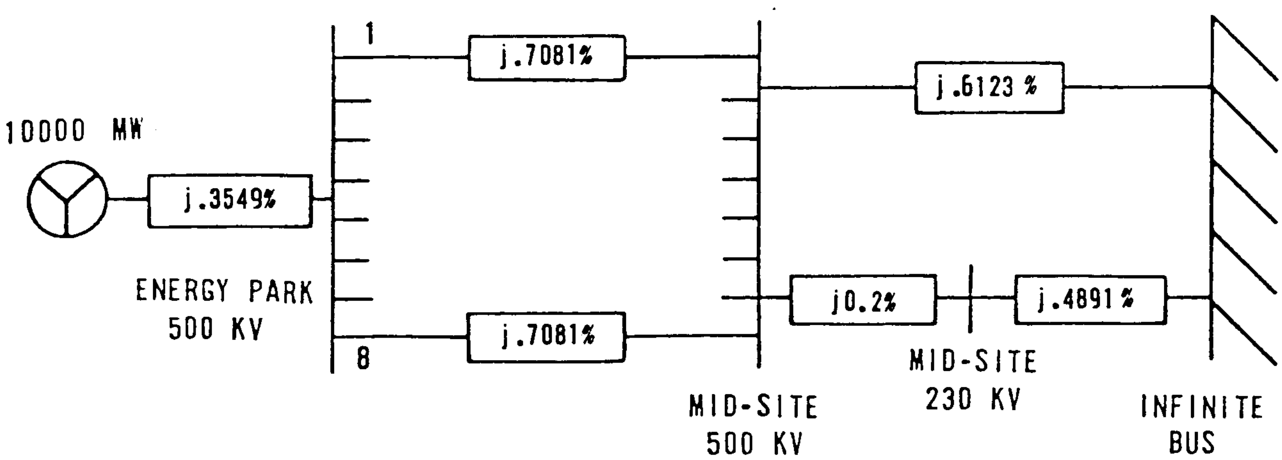
NOTE: IMPEDANCES ARE IN PERCENT ON A 100 MVA BASE

SHORT CIRCUIT DIAGRAMS

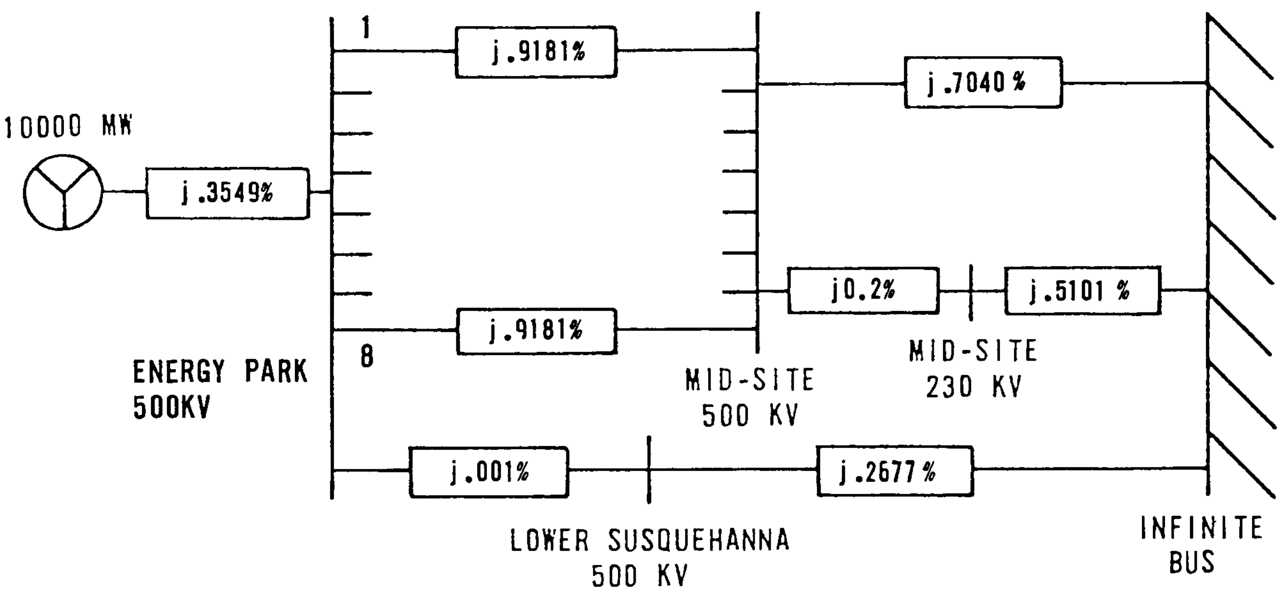
765 KV HPOPT PPP-INSULATED CABLE

9 LINES IN PARALLEL

FIG. 4-3



RADIAL SYSTEM

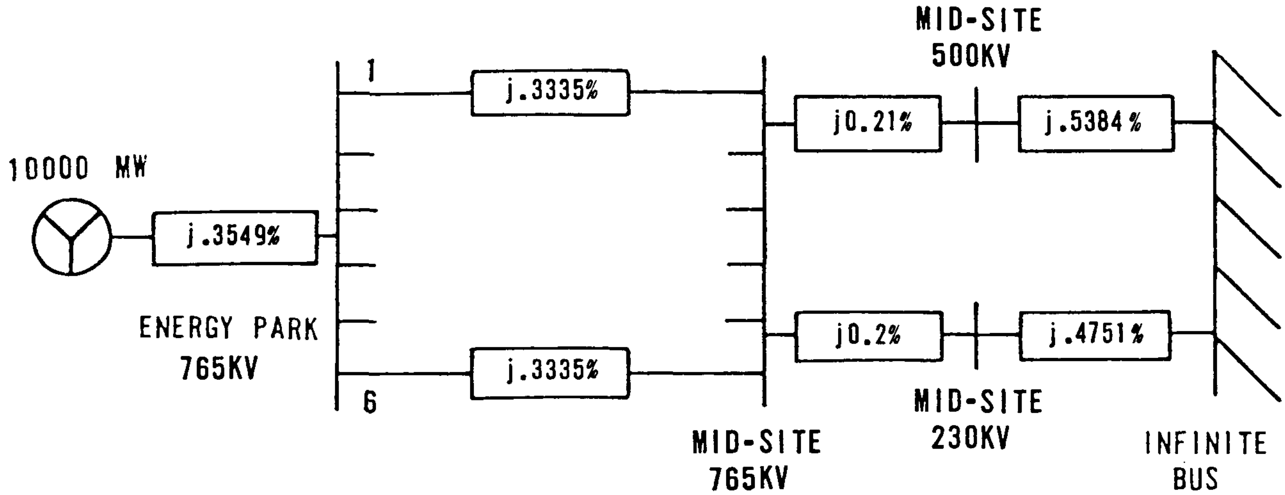


NETWORK SYSTEM

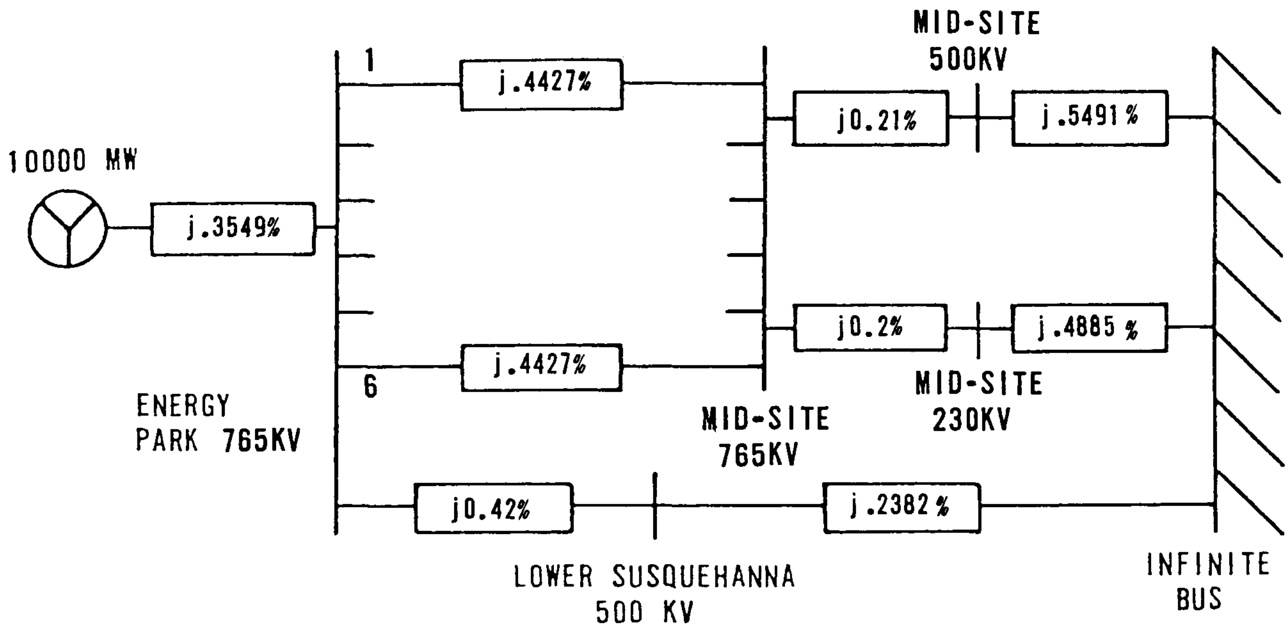
NOTE: IMPEDANCES ARE IN PERCENT ON A 100 MVA BASE

SHORT CIRCUIT DIAGRAMS
500 KV FORCE-COOLED HPOPT PPP-INSULATED CABLE
8 LINES IN PARALLEL

FIG. 4-4



RADIAL SYSTEM

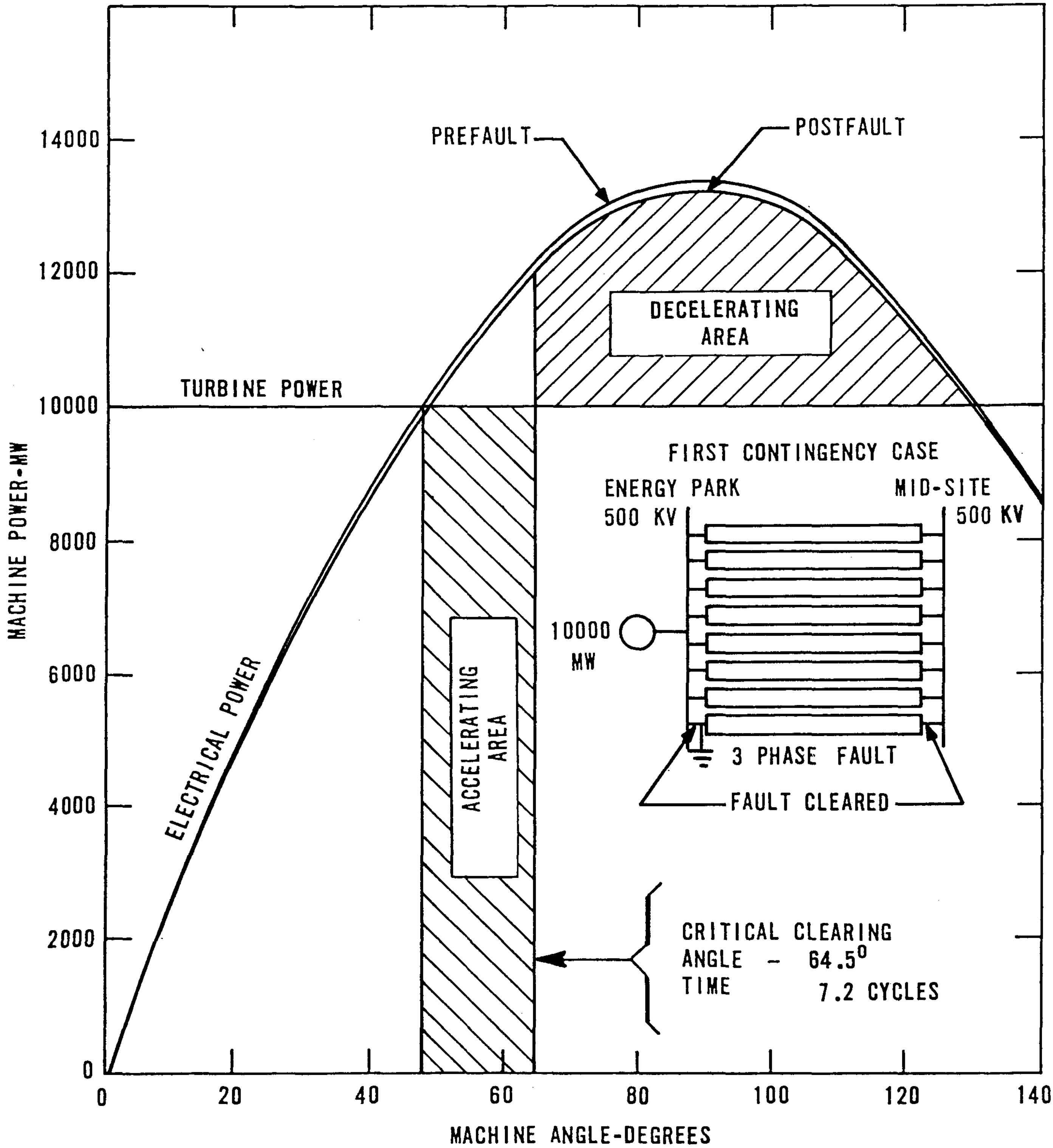


NETWORK SYSTEM

NOTE: IMPEDANCES ARE IN PERCENT ON A 100 MVA BASE

SHORT CIRCUIT DIAGRAMS
765 KV FORCE-COOLED HPOPT PPP-INSULATED CABLE
6 LINES IN PARALLEL

FIG. 4-5



POWER ANGLE CURVE
500KV HPOPT CELLULOSE-INSULATED CABLE
16 LINES IN PARALLEL

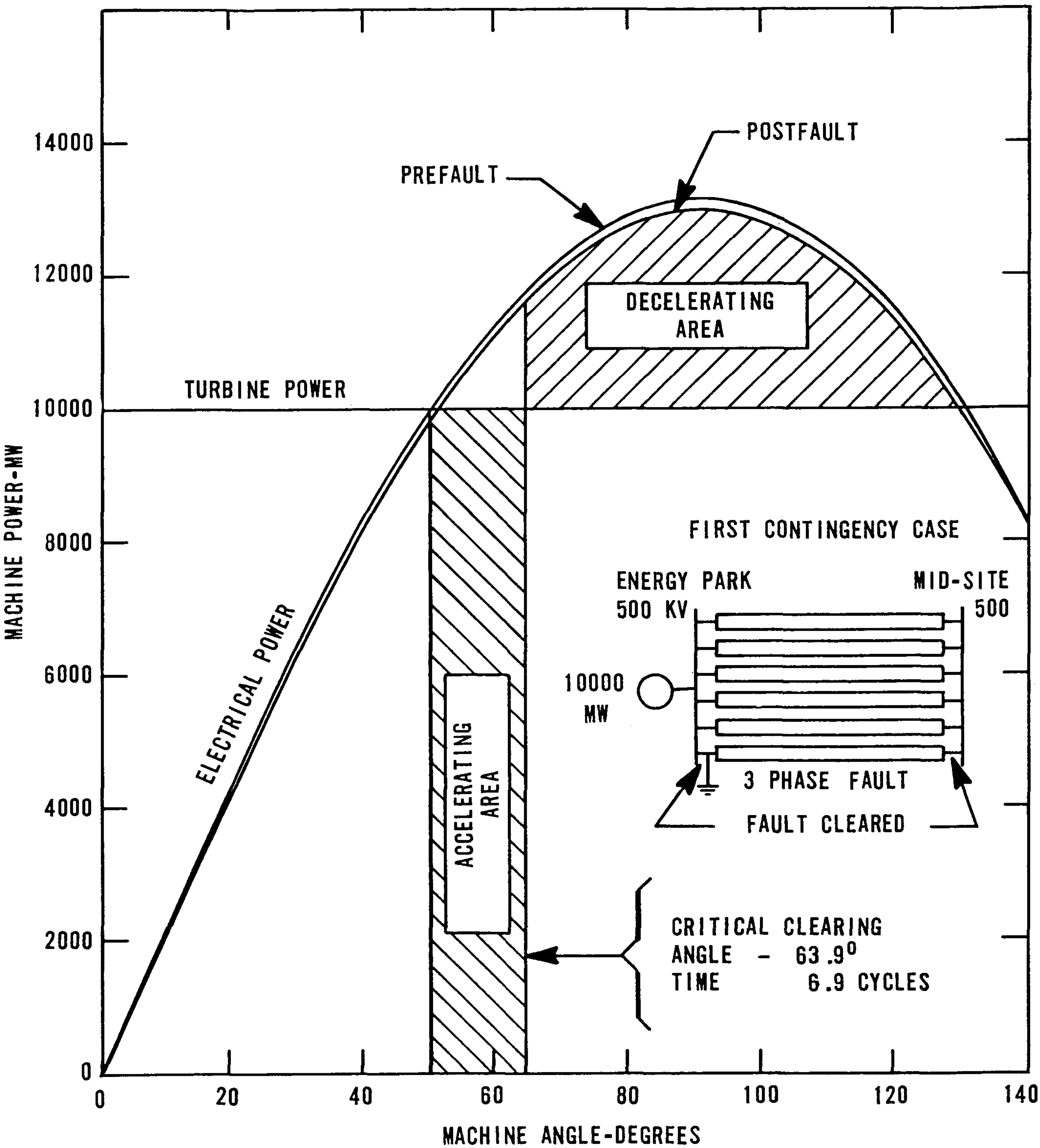
FIG. 4-6

4.4 Circuit Analysis

4.4.1 High-Pressure Oil-Filled Pipe-Type Cable (HPOPT) (cont'd)

4.4.1.3 500 kV HPOPT PPP-Insulated Cable

- Compensation. This cable required six circuits, with two lines per circuit, to provide the capability to carry the Energy Park generation to the Mid-Site substation. The system also required 1968 MVAR of shunt inductive reactance on each line to compensate for the charging current. The reactance was placed at three intermediate stations, consisting of 492 MVAR each, and at each of the endpoint substations, consisting of 246 MVAR each. Series compensation was required only in the network system, where a 13.75 ohm reactor in each line reduced the total cable system loading to 10,000 MW.
- Transient Stability. The first contingency was the most critical condition for both the radial and network systems. Power angle calculations showed that the system remained stable for a three-phase fault at Energy Park. The critical clearing time for the radial system was 6.9 cycles, and that for the network system was 11.5 cycles. The power angle curve for the first contingency in the radial system is shown in Figure 4-7.



POWER ANGLE CURVE
500 KV HPOPT PPP-INSULATED CABLE
12 LINES IN PARALLEL

FIG. 4-7

4. SYSTEM PLANNING

4.4 Circuit Analysis

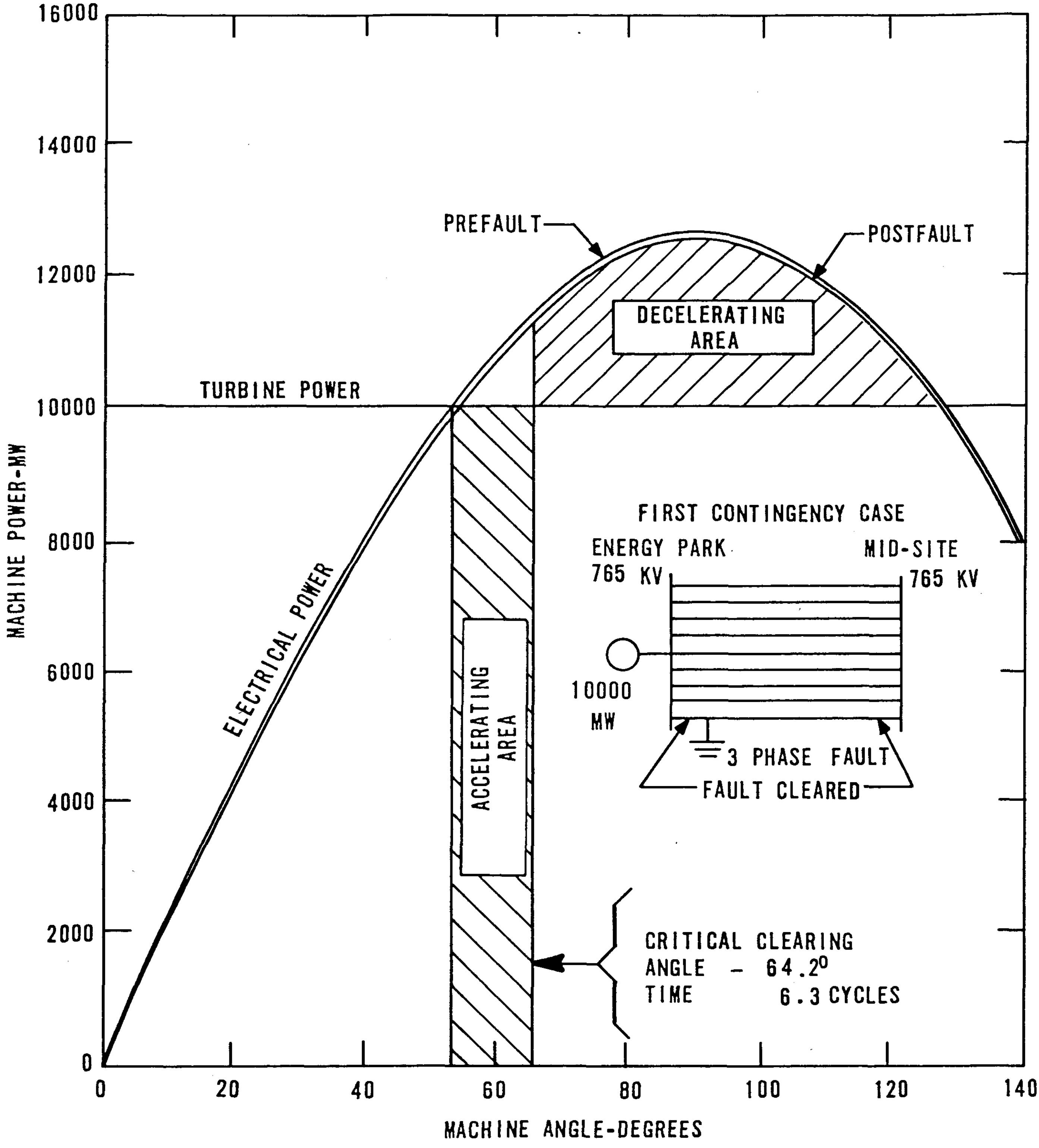
4.4.1 High-Pressure Oil-Filled Pipe-Type Cable (HPOPT) (cont'd)

4.4.1.4 765 kV HPOPT PPP-Insulated Cable

- Compensation. This system was designed with nine circuits, having one line per circuit. The shunt compensation requirements for this system were 3504 MVAR per line, which consisted of one 876 MVAR reactor at each of three intermediate stations and one 438 MVAR reactor at each endpoint substation. The network system required a reactor of 18.56 ohms in series with each circuit to meet the 10,000 MW normal loading limit.
- Transient Stability. This analysis showed that the first contingency was the most limiting for the 765 kV PPP cable system. Critical clearing times of 6.3 cycles and 9.1 cycles, for the radial and network configurations respectively, allowed the system to remain stable. Figure 4-8 shows the power angle curve for this system.

4.4.1.5 500 kV Force-Cooled HPOPT PPP-Insulated Cable

- Compensation. The forced-cooling of the 500 kV HPOPT-PPP cables increased their rating and reduced the number of lines from

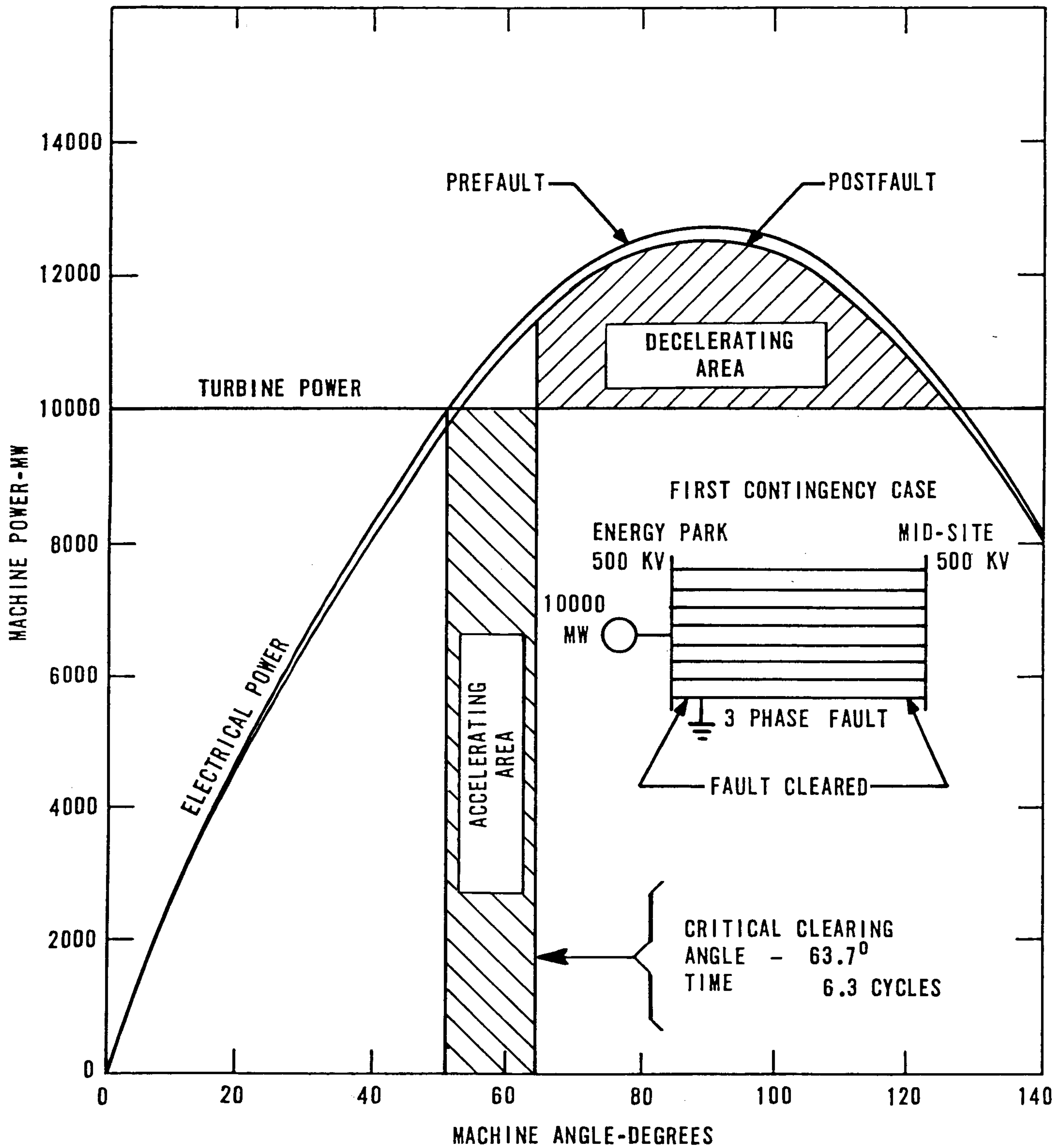


POWER ANGLE CURVE
765KV HPOPT PPP-INSULATED CABLE
9 LINES IN PARALLEL

FIG. 4-8

twelve to eight for the 500 kV HPOPT-F/C system. The shunt compensation requirements were the same as those for the HPOPT-PPP system, namely 1968 MVAR per line. Also the distribution of the reactors remained unchanged. The series inductive compensation, however, was reduced from 13.75 to 3.45 ohms per line because the net equivalent impedance from Energy Park to Mid-Site had increased from the value for the self-cooled system.

- Transient Stability. The power angle calculations showed that the system remained stable for a three-phase fault at Energy Park. The critical clearing times were 6.3 and 11.4 cycles for the radial and network systems respectively. They were lower than those for the six circuit 500 kV HPOPT-PPP because of a larger equivalent impedance between Energy Park and Mid-Site. The power angle curve of the first contingency for the radial system is shown in Figure 4-9.



POWER ANGLE CURVE
500KV FORCE-COOLED HPOPT PPP INSULATED CABLE
8 LINES IN PARALLEL

FIG. 4-9

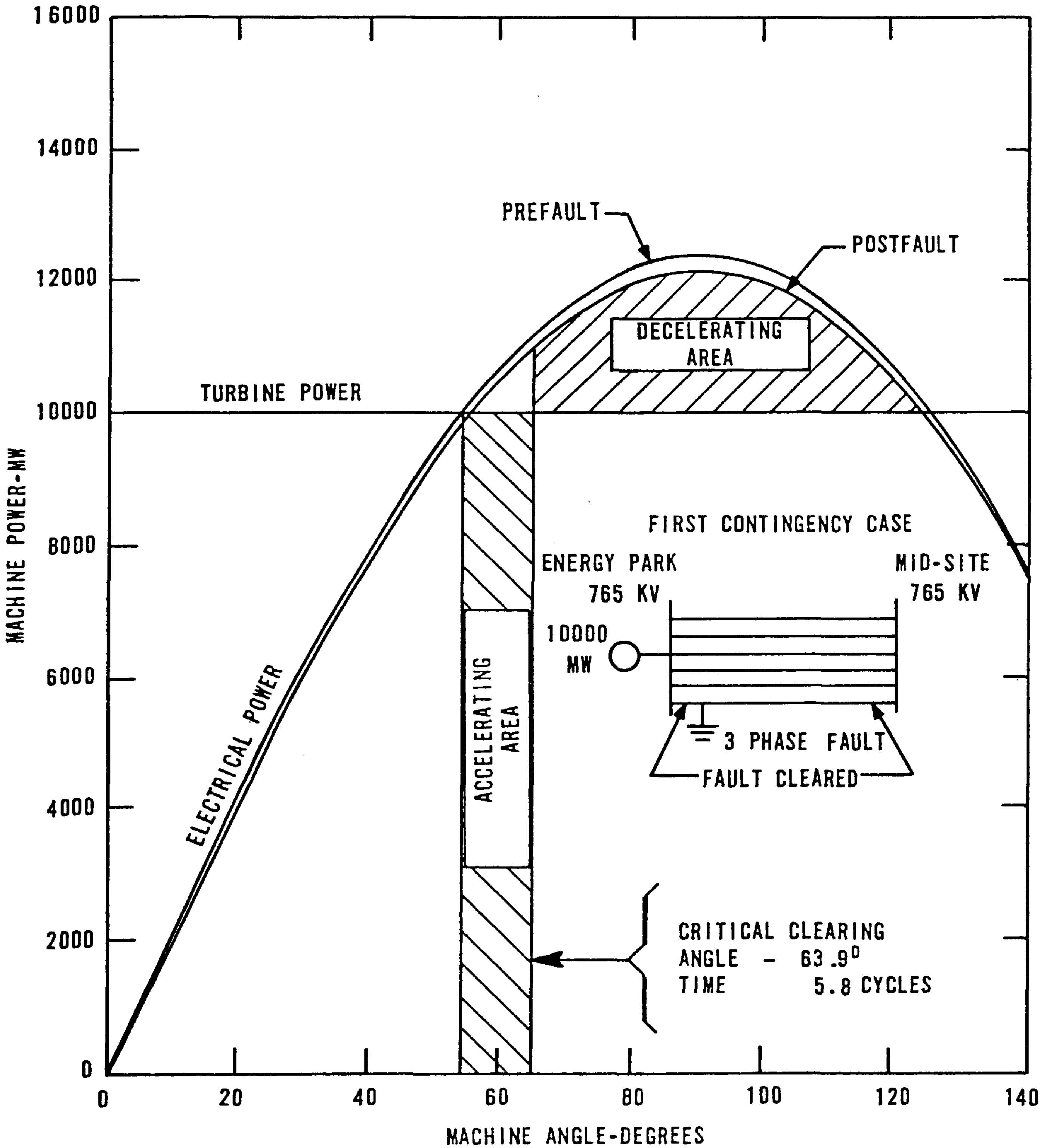
4. SYSTEM PLANNING

4.4 Circuit Analysis

4.4.1 High-Pressure Oil-Filled Pipe-Type Cable (HPOPT) (cont'd)

4.4.1.6 765 kV Force-Cooled HPOPT PPP-Insulated Cable

- Compensation. The force cooling of the 765 kV HPOPT-PPP cable allowed the number of circuits to be reduced from nine to six, with one line per circuit. The shunt compensation remained the same as that for the 765 kV HPOPT-PPP system, namely 3504 MVAR per circuit. Also, the distribution of the reactors remained unchanged. The series compensation for the 765 kV F/C system was reduced to 6.39 ohms per circuit from the 18.56 ohms per circuit needed for the non-force-cooled system.
- Transient Stability. The critical clearing times were 5.8 cycles for the radial system and 9.0 cycles for the network system. These clearing times, which were obtained for the first contingency, allowed the system to remain stable for a three-phase fault at Energy Park. The power angle curve is shown in Figure 4-10.



POWER ANGLE CURVE
765KV FORCE-COOLED HPOPT PPP INSULATED CABLE
6 LINES IN PARALLEL

FIG. 4-10

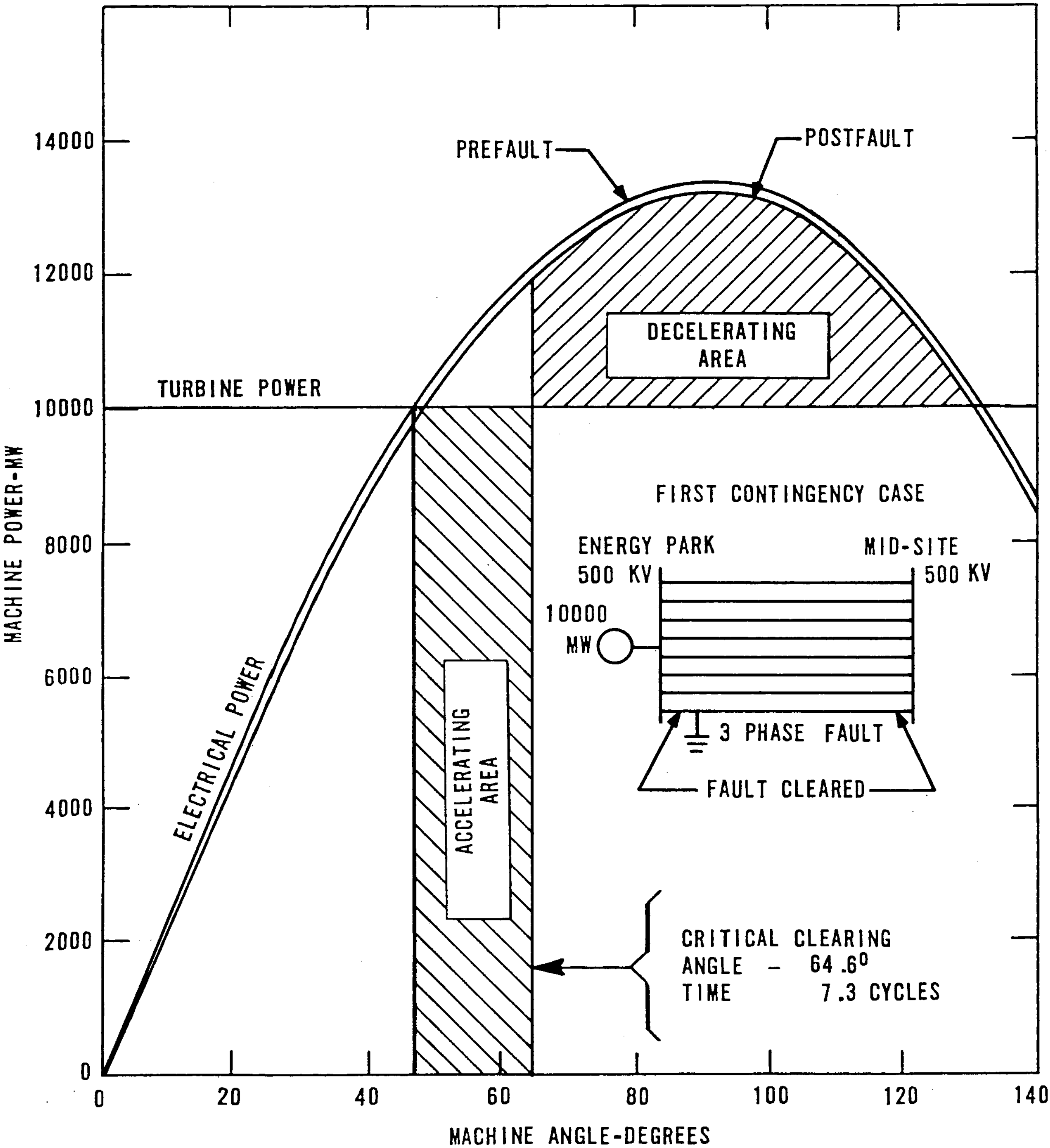
4.4 Circuit Analysis (cont'd)

4.4.2 500 kV AC Self-Contained Oil-Filled Cable (SCOF)

4.4.2.1 Compensation. The 500 kV SCOF-AC system required eight circuits, having one line per circuit, to transmit 10,000 MW from the Energy Park to the Mid-Site substation. The Mid-Site 500 kV substation was identical to the one for the 500 kV HPOPT systems, as described in Section 4.4.1.

The shunt compensation requirements for this system were 2895 MVAR per circuit. Reactors of 965 MVAR were connected at each of two intermediate substations and reactors of 482.5 MVAR were connected at the ends of each line. These values were the same for both the radial and network systems. Series compensation was required for the network system only; a 12.65 ohm reactor per line limited the total normal flow on the eight circuits to 10,000 MW.

4.4.2.2 Transient Stability. Power angle calculations showed that the SCOF-AC system would maintain stability following a three-phase fault at Energy Park. The first contingency was the most limiting for both the radial and network systems. The critical clearing times for the two systems were 7.3 and 11.5 cycles, respectively. The power angle curve for the radial system is shown in Figure 4-11.



POWER ANGLE CURVE
500KV AC SELF-CONTAINED OIL-FILLED CABLE
8 LINES IN PARALLEL

FIG. 4-11

4.4 Circuit Analysis

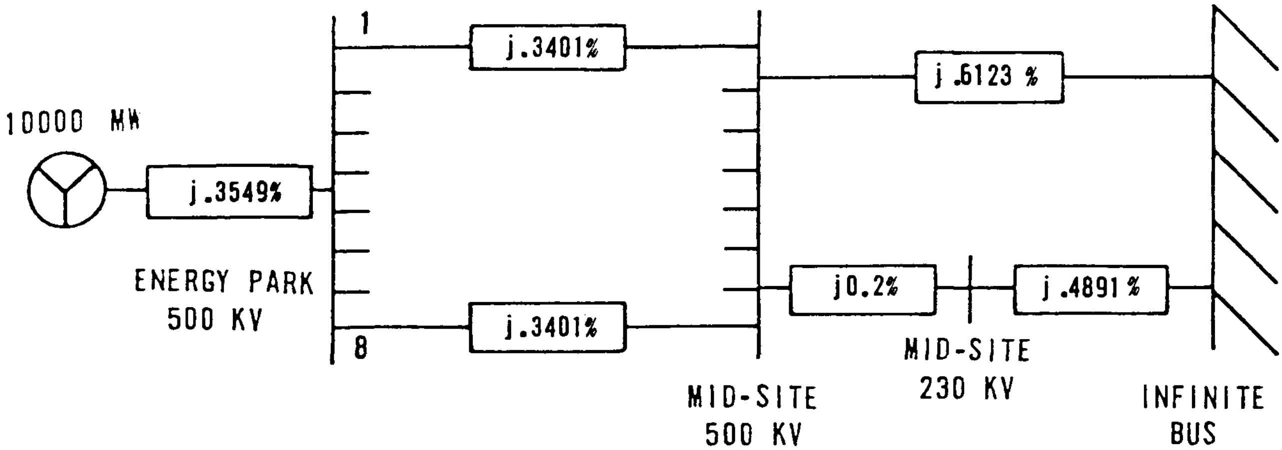
4.4.2 500 kV AC Self-Contained Oil-Filled Cable (SCOF) (cont'd)

4.4.2.3 Short Circuit Duty. The fault currents are shown in Table 4-3 and the short circuit impedance diagrams are shown in Figure 4-12.

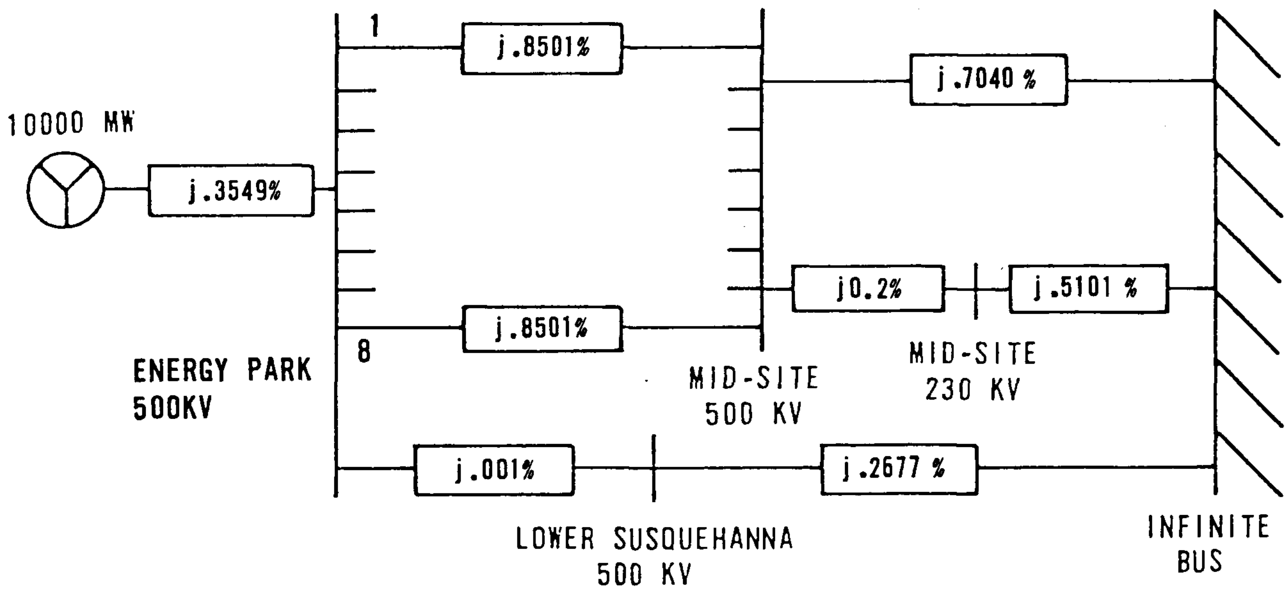
4.4.3 600 kV DC Self-Contained Oil-Filled Cable (SCOF-DC)

4.4.3.1 General. The SCOF-DC system consisted of four bipolar DC circuits between Energy Park and Mid-Site. The AC substations at the two sites operated at a voltage of 230 kV; the DC transmission lines operated at a voltage of 600 kV. At the Mid-Site 230 kV substation, in addition to the conversion equipment, there were two 500/230 kV transformers to the PJM 500 kV system. At Energy Park, the network system design required a 500/230 kV transformer to the PJM network.

4.4.3.2 Compensation. The DC system did not require any compensation in addition to the filtering equipment supplied with the converters. The compensation was not required because of the ability of the conversion equipment to regulate the line flow and the absence of line charging current.



RADIAL SYSTEM



NETWORK SYSTEM

NOTE: IMPEDANCES ARE IN PERCENT ON A 100 MVA BASE

SHORT CIRCUIT DIAGRAMS
500 KV AC SELF-CONTAINED OIL-FILLED CABLE
8 LINES IN PARALLEL

FIG. 4-12

4. SYSTEM PLANNING

4.4 Circuit Analysis

4.4.3 600 kV DC Self-Contained Oil-Filled Cable (SCOF-DC) (cont'd)

4.4.3.3 Transient Stability. The control capability of the DC conversion equipment was assumed to allow the system to remain stable for faults on the DC cables.(5)

4.4.3.4 Short Circuit Duty. Fault duties of the SCOF-DC system are restricted by the design characteristics of DC converters. Faults on the DC cables would draw limited current from the Energy Park generators due to the fast operation (less than 0.5 cycle or 0.009 sec.) of the converters; no current would be drawn from the Mid-Site AC substation because of the unidirectional operation of the converters. Faults on the AC bus at Energy Park would draw current only from the generators, due to the unidirectional operation of the DC converters.

4.4.4 Gas-Insulated Transmission Line (GITL)

4.4.4.1 General. The three types of 500 kV GITL systems required from three to five circuits to meet the loading criteria for the 10,000 MW Energy Park. The Mid-Site 500 kV substation is identical to the design for the 500 kV HPOPT systems, as described in Section 4.4.1.

4. SYSTEM PLANNING

4.4 Circuit Analysis

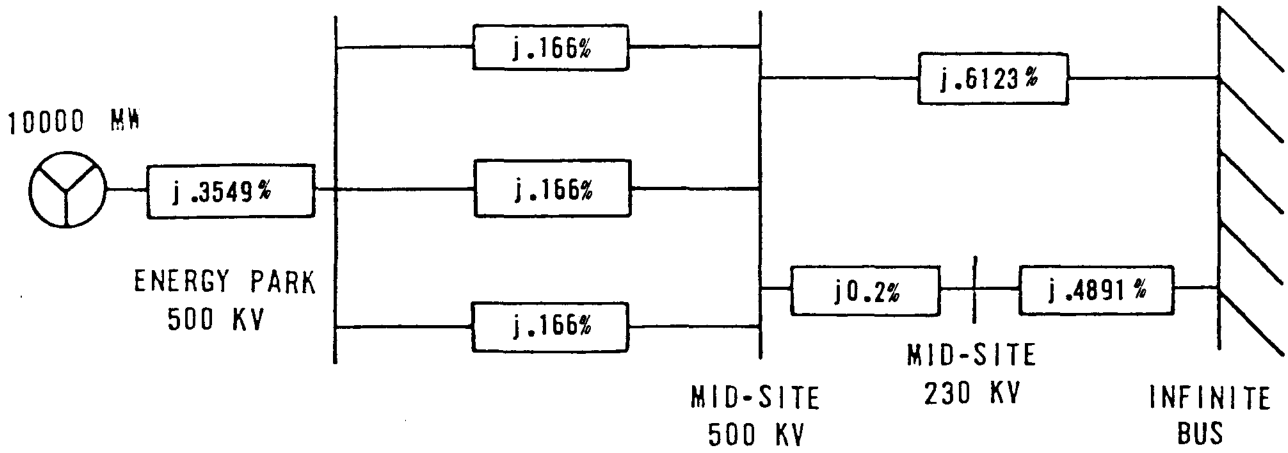
4.4.4 Gas-Insulated Transmission Line (GITL)

4.4.4.1 General (cont'd)

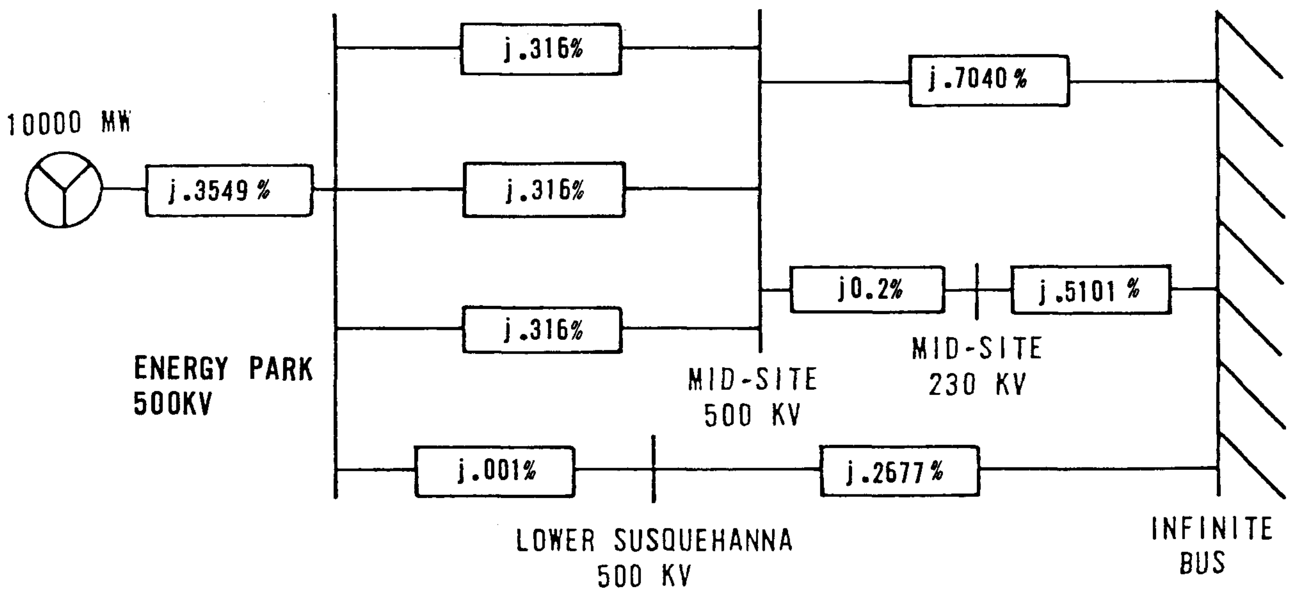
The load flow analysis of the three GITL systems showed that only the GITL-R1 system required shunt compensation. The shunt reactors were needed to prevent the generators from operating underexcited. Series compensation was required for all three designs in the network system. The compensation requirements for the three GITL systems are shown in Table 4-2.

Transient stability calculations showed that the systems would remain stable for a three-phase fault at Energy Park. The three-circuit GITL-R1 was limited by the second contingency, whereas the five-circuit GITL-F and GITL-R3 were limited by the first contingency.

The fault duties for the three GITL systems are shown in Table 4-3. The short circuit impedance diagrams for the three systems are shown in Figures 4-13 through 4-15.



RADIAL SYSTEM



NETWORK SYSTEM

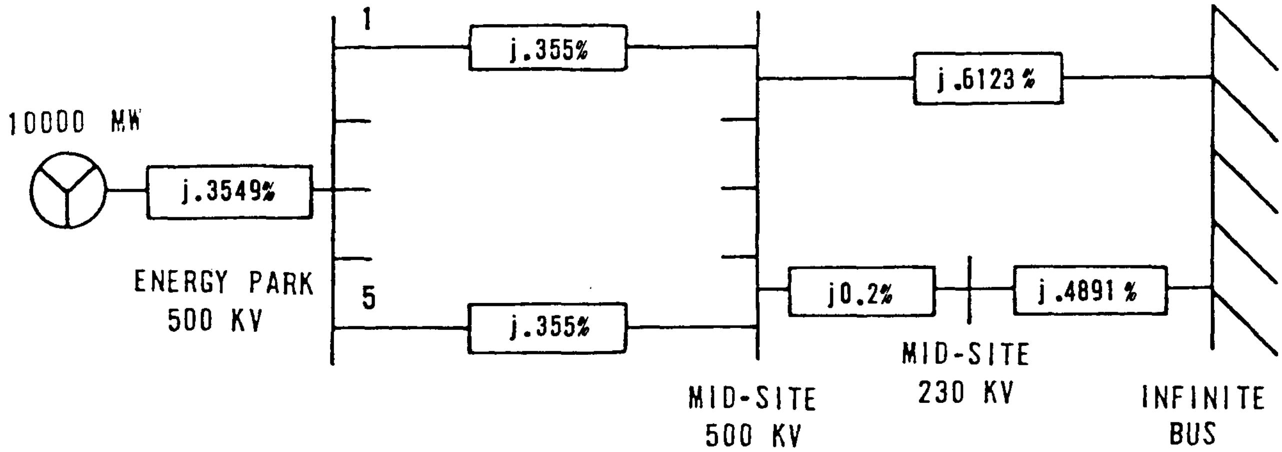
NOTE: IMPEDANCES ARE IN PERCENT ON A 100 MVA BASE

SHORT CIRCUIT DIAGRAMS

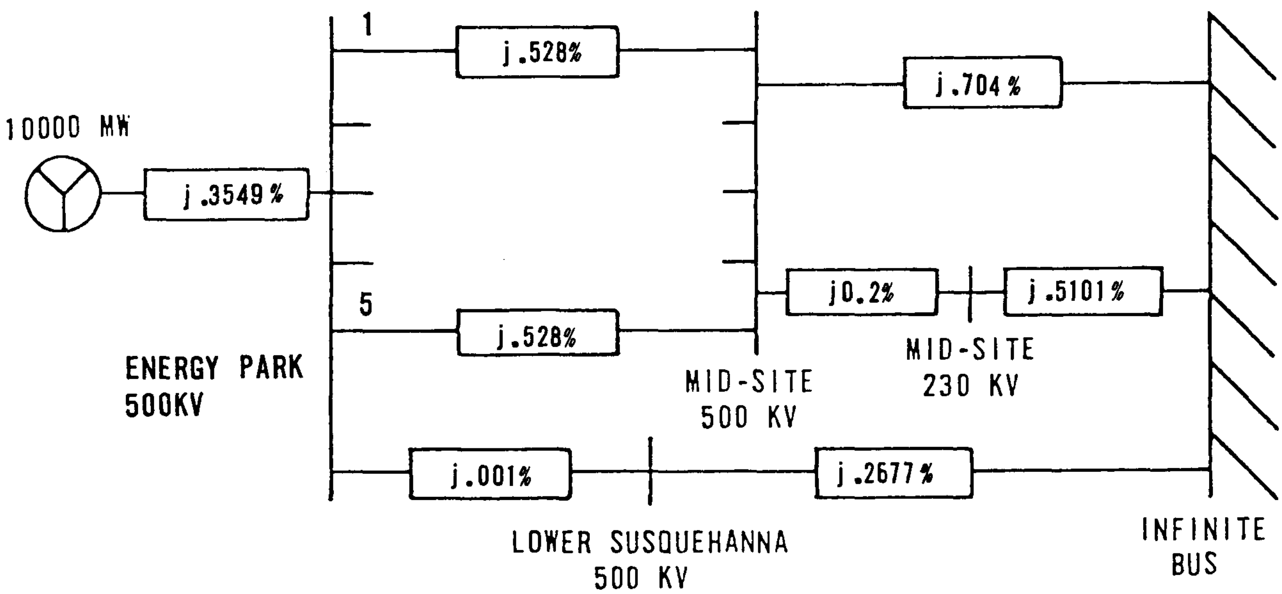
500 KV SINGLE-PHASE SF_6, GITL, RIGID SYSTEM

3 LINES IN PARALLEL

FIG. 4-13



RADIAL SYSTEM



NETWORK SYSTEM

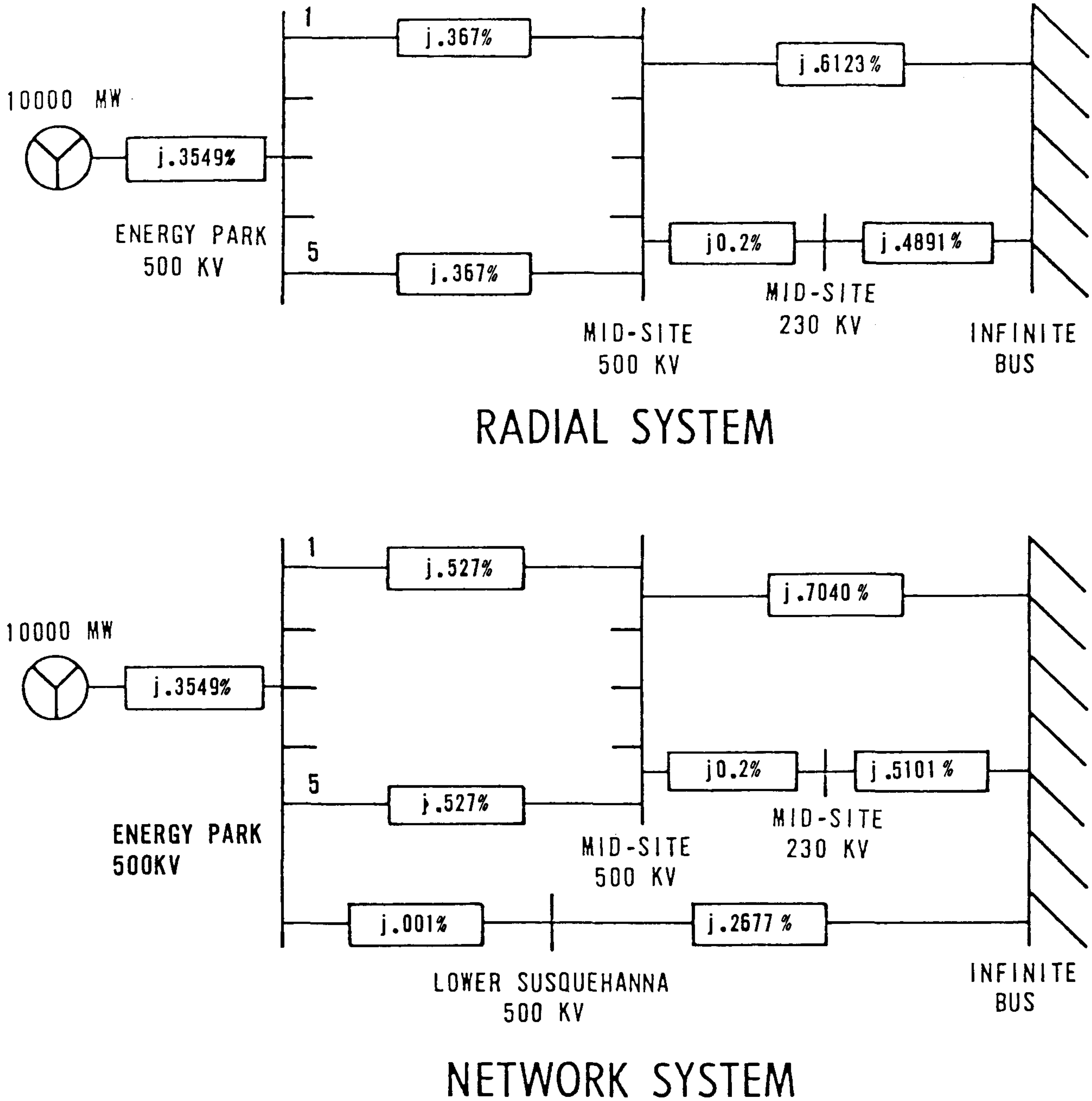
NOTE: IMPEDANCES ARE IN PERCENT ON A 100 MVA BASE

SHORT CIRCUIT DIAGRAMS

500 KV SINGLE-PHASE SF_6, GITL, FLEXIBLE SYSTEM

5 LINES IN PARALLEL

FIG. 4-14



NOTE: IMPEDANCES ARE IN PERCENT ON A 100 MVA BASE

SHORT CIRCUIT DIAGRAMS
500 KV THREE-PHASE SF_6, GITL, RIGID SYSTEM
5 LINES IN PARALLEL

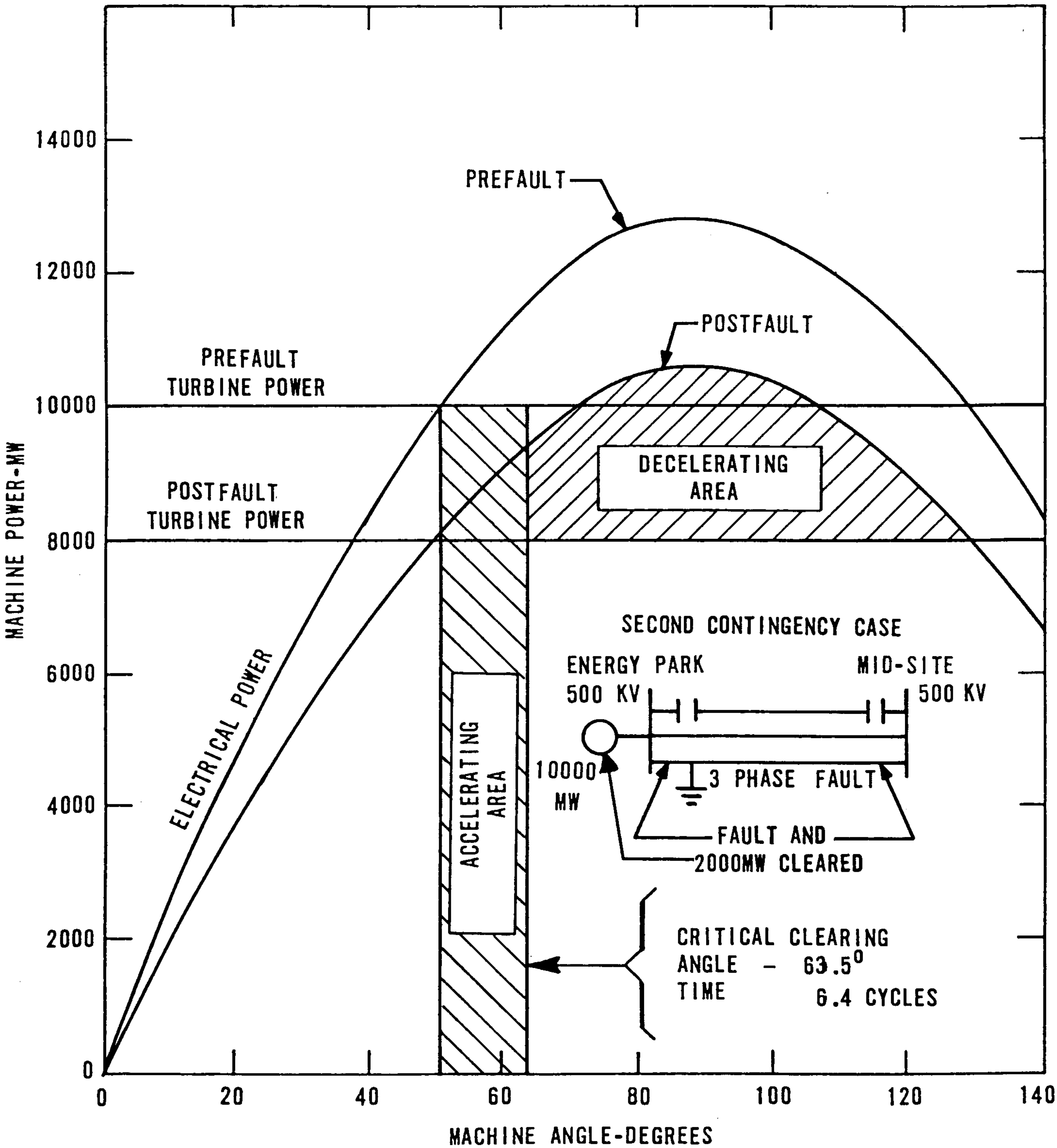
FIG. 4-15

4.4 Circuit Analysis

4.4.4 Gas-Insulated Transmission Line (GITL) (cont'd)

4.4.4.2 500 kV Single-Phase SF_6, GITL, Rigid System

- Compensation. The GITL-R1 system required only three circuits to meet the loading and reliability criteria for the 10,000 MW Energy Park. Shunt reactors of 380 MVAR per circuit, with 190 MVAR at each endpoint substation, were required for the radial system, based on six generators operating and three circuits in service. With seven to ten generators operating, the shunt compensation caused the generators to operate in the overexcited range; that is, with a lagging power factor. Based on identical conditions, the network system required only 130 MVAR per circuit. In addition, the network system required a series reactor of 3.75 ohms per circuit.
- Transient Stability. The critical clearing times for the radial and network systems were 6.4 and 11.1 cycles, respectively, for the second contingency. This condition required the clearing of two generators (2000 MW) when the faulted circuit was cleared, for the system to remain stable. The power angle curve for this cable system is shown in Figure 4-16.



POWER ANGLE CURVE
500KV SINGLE-PHASE SF 6, GITL, RIGID SYSTEM
3 LINES IN PARALLEL

FIG. 4-16

4. SYSTEM PLANNING

4.4 Circuit Analysis

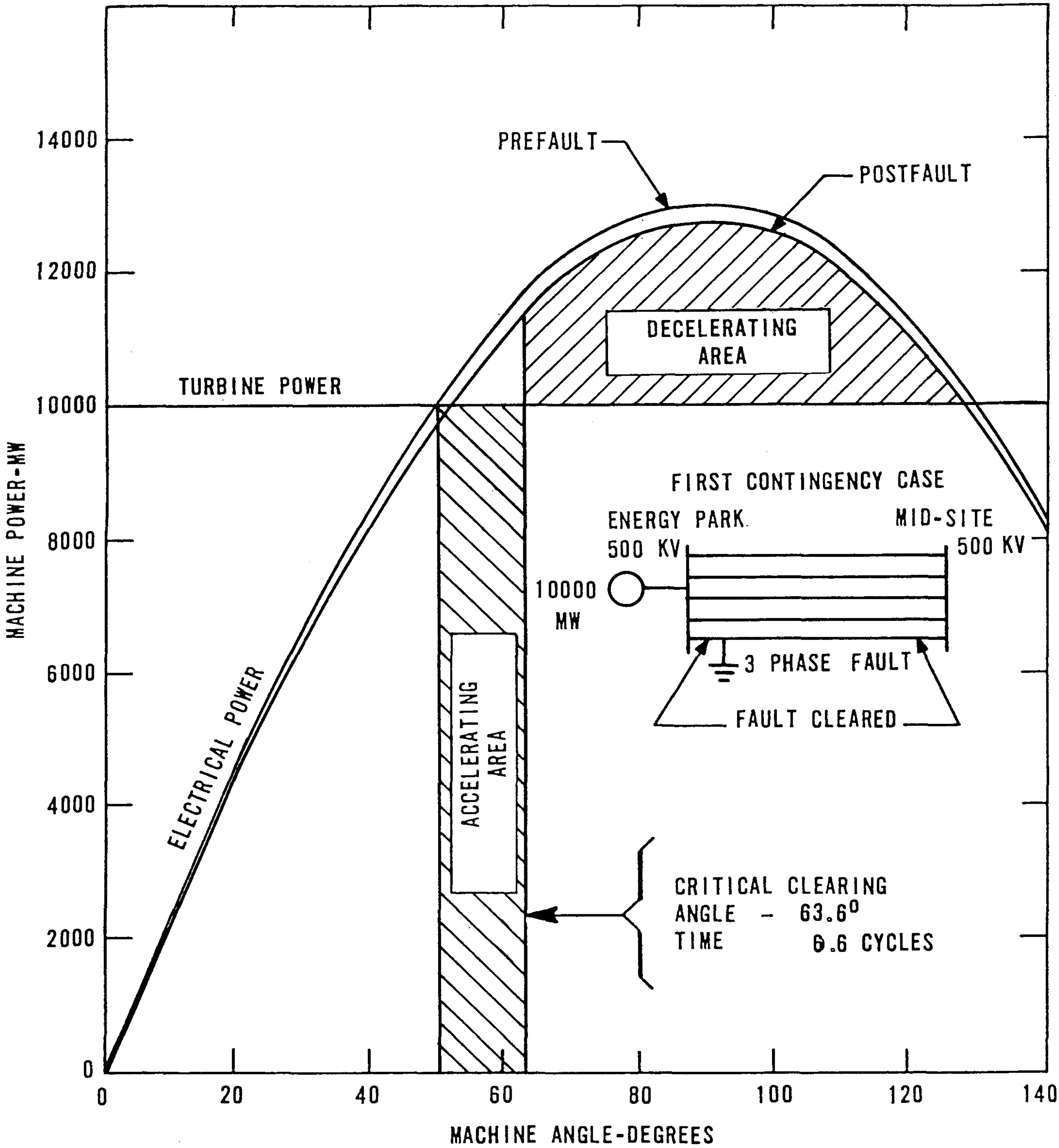
4.4.4 Gas-Insulated Transmission Line (GITL) (cont'd)

4.4.4.3 500 kV Single-Phase SF_6, GITL, Flexible System

- Compensation. This system required five circuits to transmit the 10,000 MW of Energy Park generation to the Mid-Site substation. The GITL-F system required no shunt compensation for either the radial or network systems. The only compensation necessary was a 4.25-ohm reactor per line to limit the total cable MW flow in the network system.
- Transient Stability. The power angle calculations resulted in critical clearing times of 6.6 cycles for the radial system and 11.5 cycles for the network system. Figure 4-17 shows the power angle curve for the GITL-F system.

4.4.4.4 500 kV Three-Phase SF_6, GITL, Rigid System

- Compensation. The GITL-R3 system used five circuits to connect the Energy Park generation to the Mid-Site substation. As in the case of the GITL-F design, there was no shunt compensation required. However, a series reactor of 4 ohms was necessary in each circuit of the network system to limit the cable loadings.



POWER ANGLE CURVE
500KV SINGLE-PHASE SF6, GITL, FLEXIBLE SYSTEM
5 LINES IN PARALLEL

FIG. 4-17

4. SYSTEM PLANNING

4.4 Circuit Analysis

4.4.4 Gas-Insulated Transmission Line (GITL)

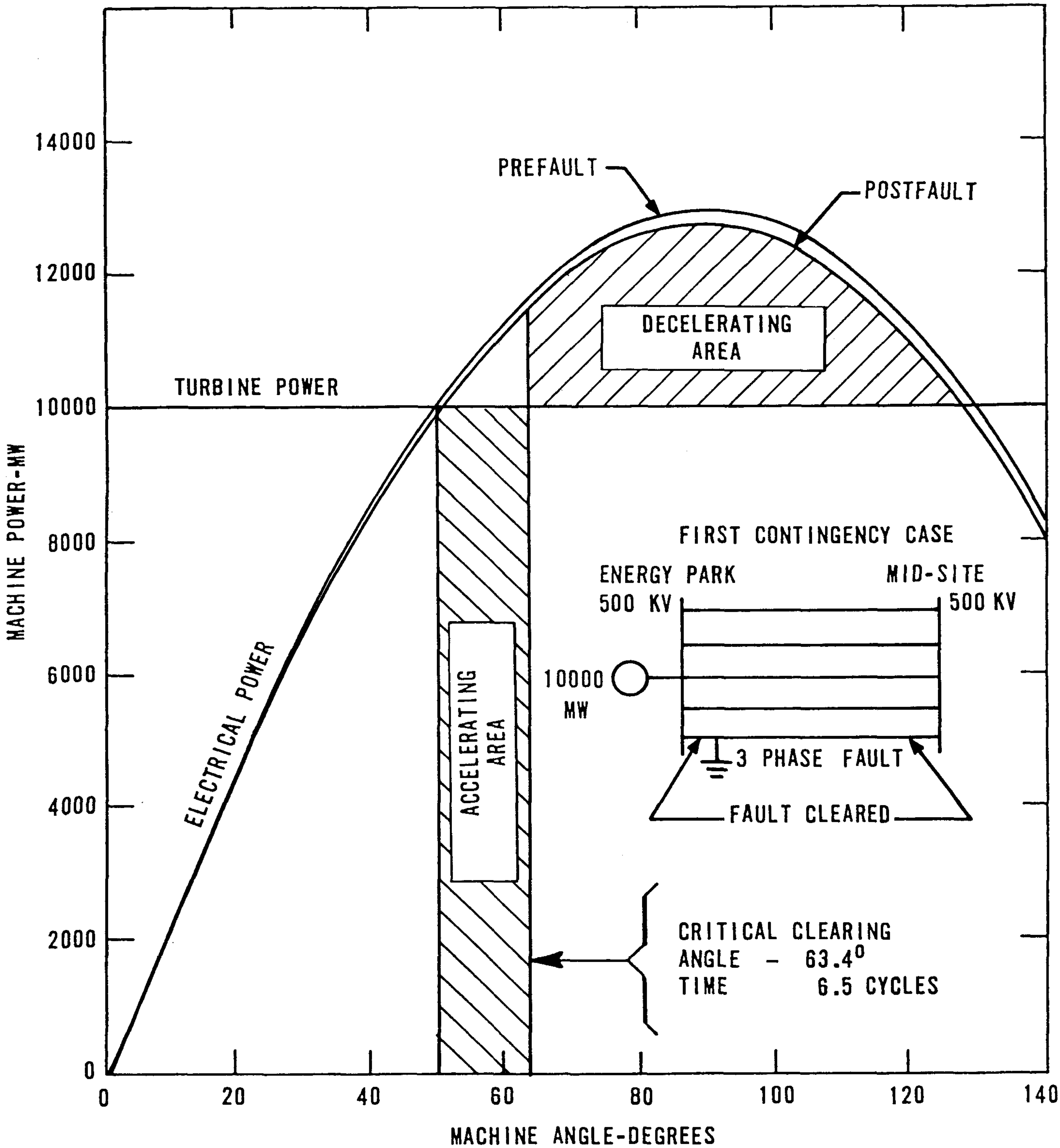
4.4.4.4 500 kV Three-Phase SF_6, GITL, Rigid System (cont'd)

- Transient Stability. The critical clearing times for the first contingency were 6.5 cycles for the radial system and 11.5 cycles for the network system. The power angle curve for the radial system is shown in Figure 4-18.

4.4.5 500 kV Resistive Cryogenic Cable (RC)

4.4.5.1 Compensation. This system required four circuits to transmit 10,000 MW to Mid-Site. The Mid-Site 500 kV substation was identical to the one described in Section 4.4.1, for the 500 kV HPOPT systems.

The compensation requirements, shown in Table 4-2, were 2695 MVAR per circuit for both the radial and network systems. One 1348 MVAR reactor was connected to each circuit at the endpoint substations. In addition, the network system used 4 ohms of series capacitors per circuit to maintain the required loadings by reducing the equivalent cable system impedance.



POWER ANGLE CURVE
500KV THREE-PHASE SF_6, GITL, RIGID SYSTEM
5 LINES IN PARALLEL

FIG. 4-18

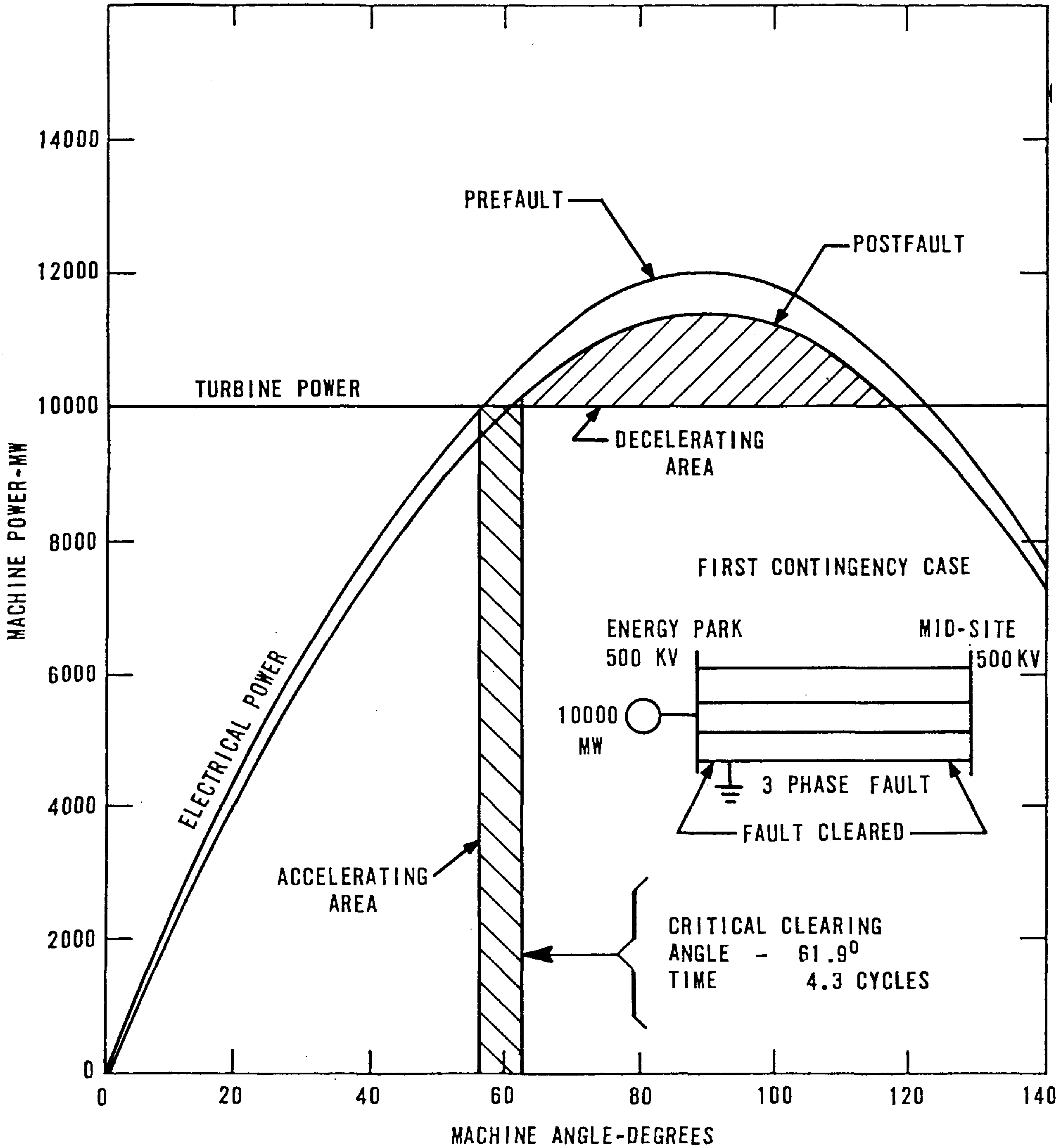
4. SYSTEM PLANNING

4.4 Circuit Analysis

4.4.5 500 kV Resistive Cryogenic Cable (RC) (cont'd)

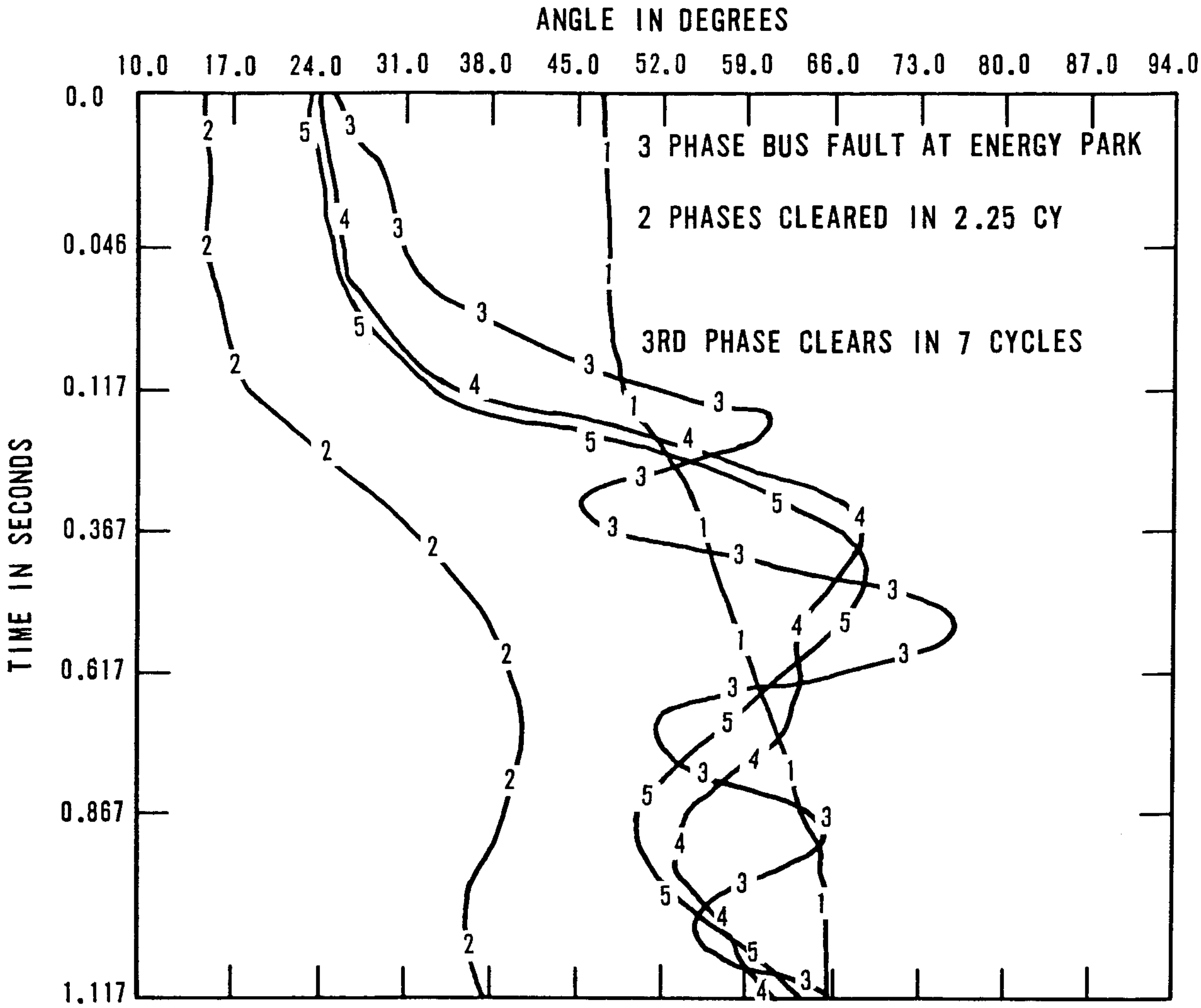
4.4.5.2 Transient Stability. The system remained stable for a three-phase fault at Energy Park. Critical clearing times of 4.3 and 11.0 cycles, for the radial and network systems respectively, showed that the first contingency was the limiting condition. The power angle curve for the 500 kV RC system is shown in Figure 4-19.

The Transient Stability computer program[2] was used to verify the power angle calculations and to show that the system would remain stable for a three-phase fault with delayed clearing due to a single-pole stuck breaker. Figure 4-20 shows the generator swing curves for five generating units; curves #1 and #2 represent the machine angle for two units in the PJM system and curves #3, #4, and #5 represent the machine angle for two units at Energy Park. After the fault occurred, two phases of the faulted circuit cleared in 2.25 cycles (0.0375 sec.) and the third phase cleared in 7 cycles (0.1167 sec.). Curves #1 and #2 represent, respectively, a coal-fueled steam generator in western Pennsylvania and a nuclear-fueled steam generator which will be operating in the Philadelphia Electric Company system by the 1990's. Curves #3 and



POWER ANGLE CURVE
500KV RESISTIVE CRYOGENIC CABLE
4 LINES IN PARALLEL

FIG. 4.19



SYMBOL	BUS	NAME
1	31	KEYSTONE 500
2	35	LIMERICK 500
3	999	ENERGY P 500
4	999	ENERGY P 500
5	999	ENERGY P 500

GENERATOR SWING CURVES
500 KV RESISTIVE CRYOGENIC CABLE
4 LINES IN PARALLEL

FIG. 4-20

4. SYSTEM PLANNING

4.4 Circuit Analysis

4.4.5 500 kV Resistive Cryogenic Cable (RC)

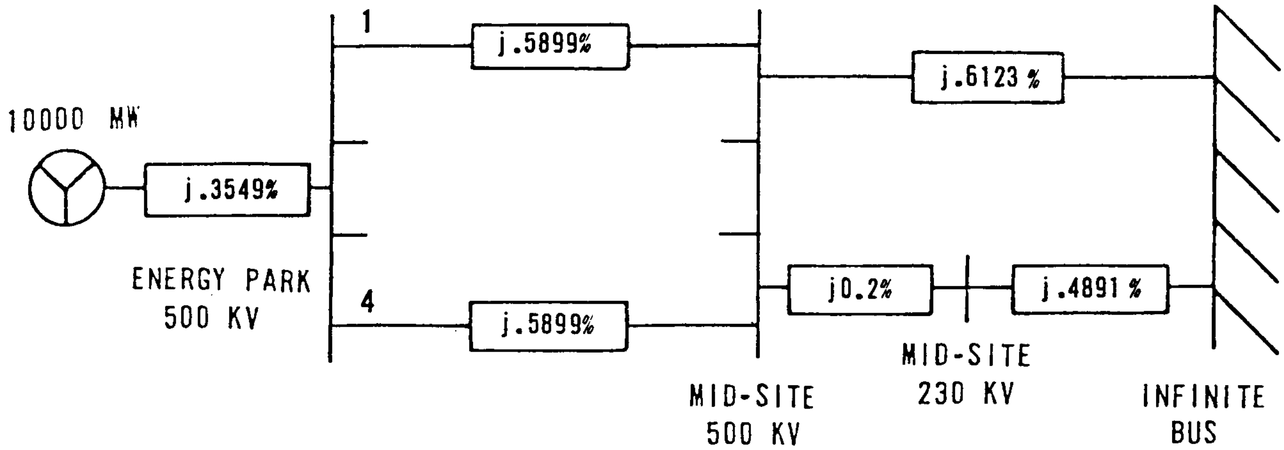
4.4.5.2 Transient Stability (cont'd)

#4 represent the high- and low-pressure turbines of a coal-fueled steam generator at Energy Park. Curve #5 represents a nuclear-fueled steam generator at Energy Park.

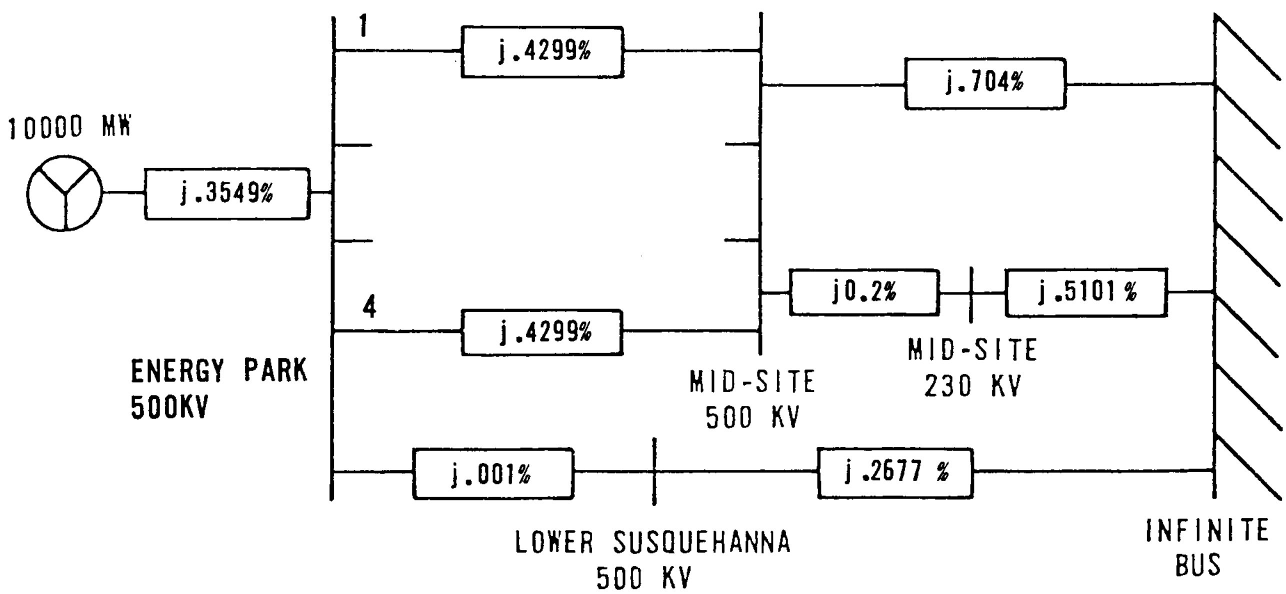
4.4.5.3 Short Circuit Duty. The fault duties for the RC system are shown in Table 4-3. The short circuit impedance diagrams are shown in Figure 4-21.

4.4.6 Superconducting Cable

4.4.6.1 General. The three superconducting cable systems, of which two were AC and one was DC, had three circuits connecting Energy Park to the Mid-Site substation. The two AC systems operated at 230 kV and the DC system operated at 300 kV. The Mid-Site 230 kV AC substation contained two 500/230 kV transformers to provide power to the PJM 500 kV grid. The Energy Park substation in the AC network systems had one 500/230 kV transformer to provide a connection to the grid.



RADIAL SYSTEM



NETWORK SYSTEM

NOTE: IMPEDANCES ARE IN PERCENT ON A 100 MVA BASE

SHORT CIRCUIT DIAGRAMS
500 KV RESISTIVE CRYOGENIC CABLE
4 LINES IN PARALLEL

FIG. 4-21

4.4 Circuit Analysis

4.4.6 Superconducting Cable

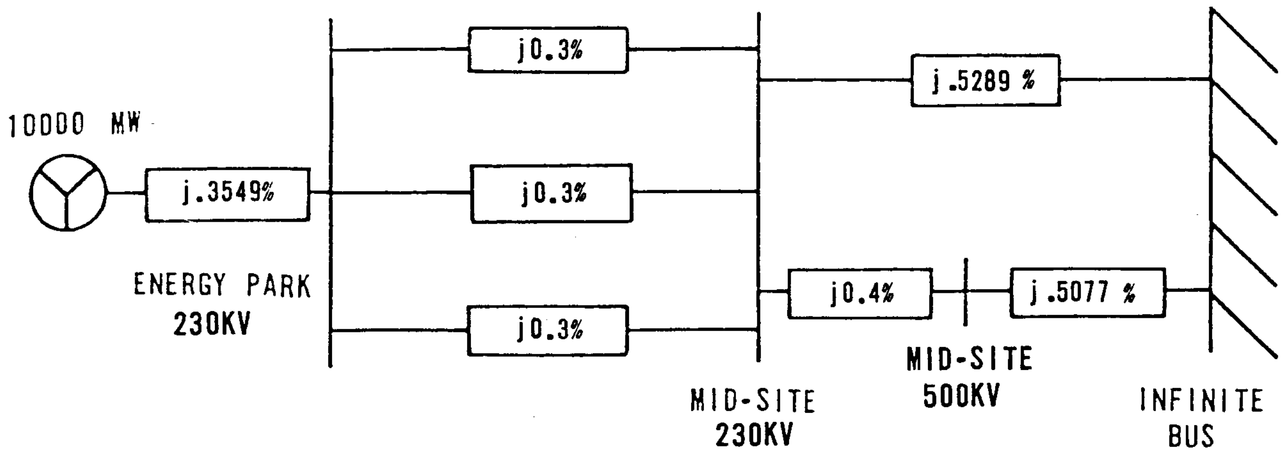
4.4.6.1 General (cont'd)

The AC systems required only series compensation. Series capacitors were used to reduce the equivalent cable impedance from Energy Park to Mid-Site to allow the system to meet the transient stability criteria. The DC system required no compensation.

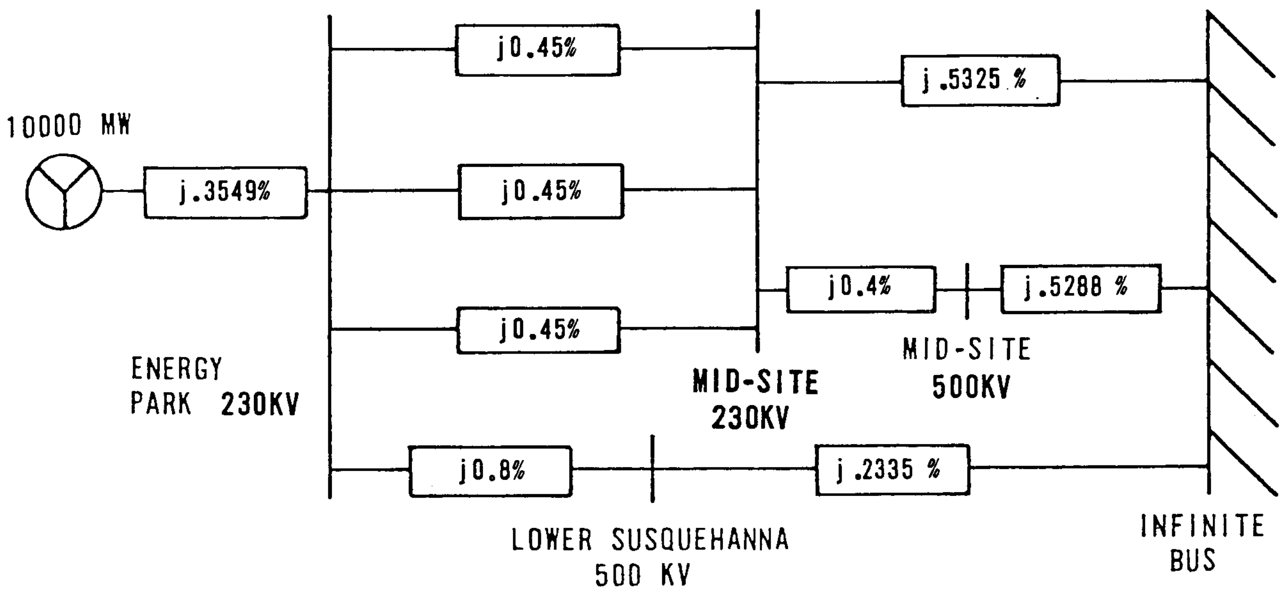
The short circuit analysis of the two AC systems showed that the fault currents, shown in Table 4-3, were as high as 135,000 A, for faults at Energy Park. As noted, the use of special sequential relaying arrangements would reduce these values to within the interrupting capabilities of the breakers. The short circuit impedance diagrams for the AC systems are shown in Figures 4-22 and 4-23.

4.4.6.2 230 kV Superconducting Cable

- Compensation. The radial system required 0.29 ohms of series capacitors per circuit, which was 13% of the cable impedance, to enable the system to meet the transient stability criteria. The capacitors were connected to each circuit at the Energy Park bus. Voltage calculations



RADIAL SYSTEM

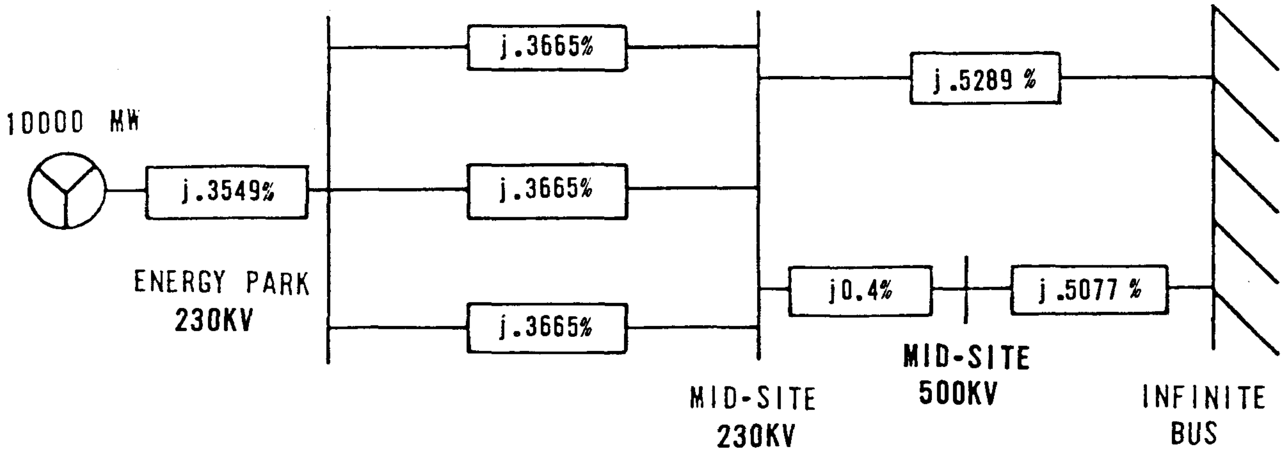


NETWORK SYSTEM

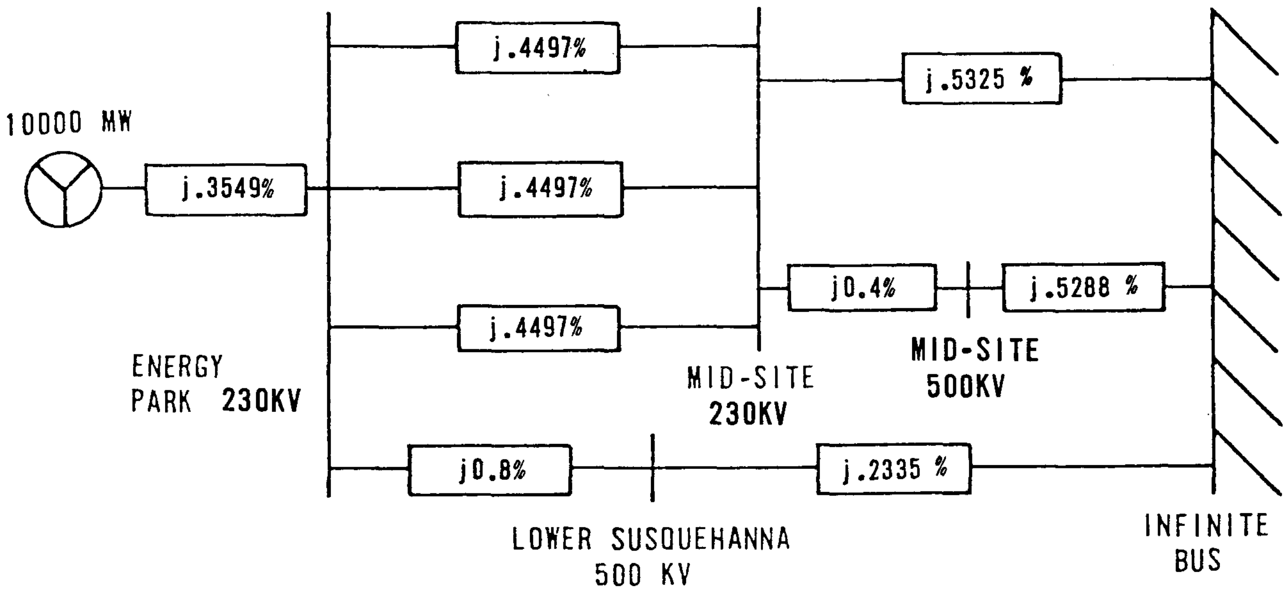
NOTE: IMPEDANCES ARE IN PERCENT ON A 100 MVA BASE

SHORT CIRCUIT DIAGRAMS
230 KV SUPERCONDUCTING CABLE
3 LINES IN PARALLEL

FIG. 4-22



RADIAL SYSTEM



NETWORK SYSTEM

NOTE: IMPEDANCES ARE IN PERCENT ON A 100 MVA BASE

SHORT CIRCUIT DIAGRAMS

230 KV SUPERCONDUCTING CABLE, RIGID SYSTEM

3 LINES IN PARALLEL

FIG. 4-23

4. SYSTEM PLANNING

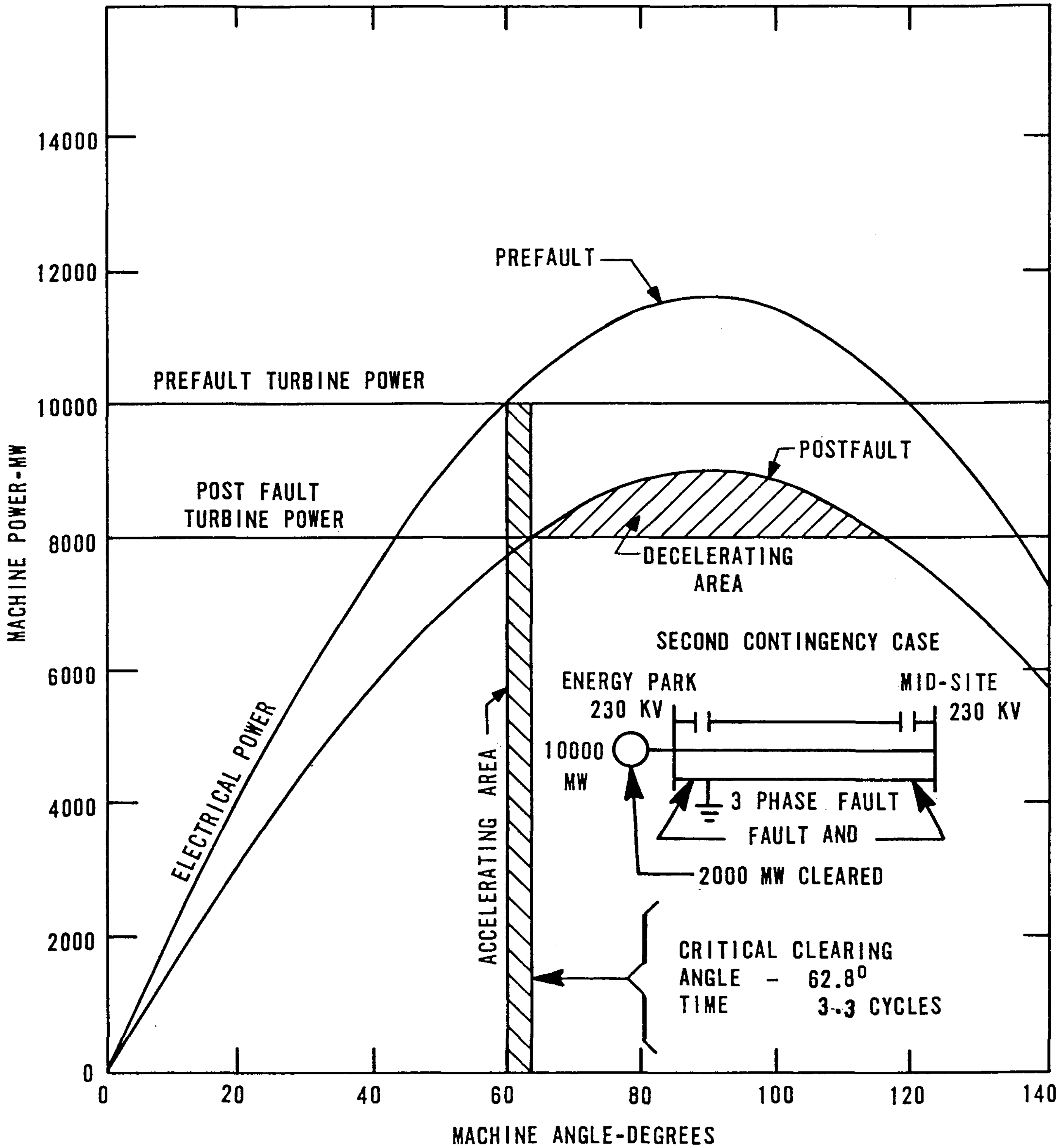
4.4 Circuit Analysis

4.4.6 Superconducting Cable

4.4.6.2 230 kV Superconducting Cable (cont'd)

performed in the load flow analysis showed that the capacitors did not cause line voltage problems. Under normal operating conditions, the line voltage did not exceed 1.06 p.u. Volts.

- Transient Stability. Series capacitors were needed for the radial system to remain stable following a three-phase fault with one circuit out for maintenance. The critical clearing time was increased from 2.2 cycles, to 3.3 cycles by reducing the net cable impedance with series capacitors and by clearing 2000 MW of generation at Energy Park. As noted in Section 4.3.2, the primary protection clearing time was increased from 2.75 cycles to 3.25 cycles to allow for the operation of the special sequential relaying. The network system, which had a critical clearing time of 7.0 cycles, did not require any compensation. Figure 4-24 shows the power angle curve for the 230 kV SC system.



POWER ANGLE CURVE
230KV SUPERCONDUCTING CABLE
3 LINES IN PARALLEL

FIG. 4-24

4. SYSTEM PLANNING

4.4 Circuit Analysis

4.4.6 Superconducting Cable (cont'd)

4.4.6.3 230 kV Superconducting Cable, Rigid System

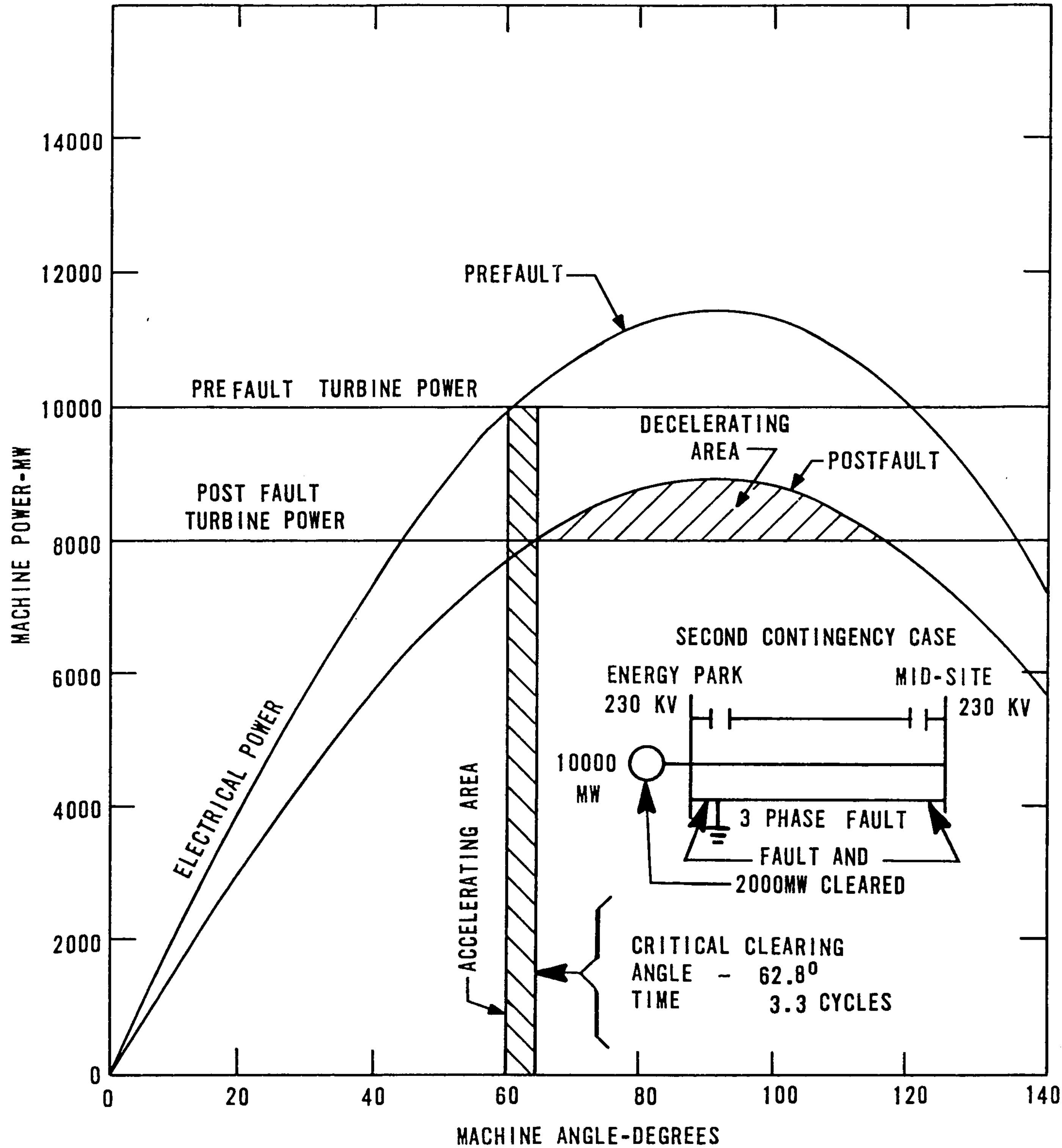
- Compensation. The radial system required 10.92 ohms of series capacitors per circuit, which was 85% of the cable impedance, to enable the system to meet the transient stability criteria. Voltage calculations showed that it was necessary to distribute the capacitors along the cables to prevent line voltages above 1.10 p.u. Volts, under normal operating conditions. Six intermediate stations, each with 1.56 ohms of series capacitors, and two endpoint stations, each with 0.78 ohms of series capacitors, would be necessary to prevent line voltages from exceeding 1.10 p.u. Volts.*

  * The incremental cost of distributing the capacitors along the cable was not included in the cost of the system.

  The network system required 10.48 ohms of series capacitors per circuit, which is 82% of the cable impedance, to enable the system to meet the transient stability and network-system loading criteria. The series capacitors in the network system would also have to be distributed along the cables to prevent the line voltages from exceeding 1.10 p.u. Volts. Six intermediate stations, each with 1.50 ohms of series capacitors, and two endpoint stations, each with 0.75 ohms of series capacitors would be required.*

* The incremental cost of distributing the capacitors along the cable was not included in the cost of the system.

- Transient Stability. Series capacitors were needed for the radial system to remain stable following a three-phase fault with one circuit out for maintenance. The critical clearing time of 3.3 cycles was achieved by the same procedure as described for the 230 kV SC system. The critical clearing time for the network system was 6.8 cycles. Figure 4-25 shows the power angle curve for the 230 kV SC-R system.



POWER ANGLE CURVE
230KV SUPERCONDUCTING CABLE, RIGID SYSTEM
3 LINES IN PARALLEL

FIG. 4-25

4.4.6.3 230 kV Superconducting Cable, Rigid System (cont'd)

- General. The ERDA/EPRI contractor originally proposed using a superconducting cable that would have an operating voltage of 138 kV. At this voltage, the percent of series compensation would be larger than the 85% value for the 230 kV system, to achieve the same critical clearing time. In addition, the lower operating voltage would cause the fault duties to exceed the 135,000 A value which was calculated for the 230 kV system. An increase in the fault duties could cause an increase in the time required to clear the fault. Therefore, it was decided that 230 kV would be more suitable for this system than 138 kV.

4.4.6.4 300 kV DC Superconducting Cable

- General. This system consisted of three monopolar DC circuits from Energy Park to Mid-Site. The generation voltage at Energy Park was converted to 300 kV DC; at Mid-Site, the 300 kV DC was converted to 230 kV AC. In addition to the conversion equipment at Mid-Site, two 500/230 kV transformers were needed for the connection to the PJM 500 kV grid. In the network system, the

4. SYSTEM PLANNING

4.4 Circuit Analysis

4.4.6 Superconducting Cable

4.4.6.4 300 kV DC Superconducting Cable (cont'd)

Energy Park substation contained a 300 kV DC/500 kV AC converter to provide a connection to the PJM grid.

- Compensation. The DC system did not require any compensation in addition to the filtering equipment supplied with the converters (refer to Section 4.4.3.2).
- Transient Stability. The control capability of the DC conversion equipment was assumed to allow the system to remain stable for faults on the DC cables.[5]
- Short Circuit Duty. Fault duties of the SC-DC system were restricted by the design characteristics of the DC converters (refer to Section 4.4.3.4).

4.4.7 500 kV Aerial/Underground System

4.4.7.1 Compensation. The aerial system consisted of 96.5 km (60 mi.) of five aerial circuits, from Energy Park to the Philadelphis suburbs, and 9.7 km (6 mi.) of five circuit GITL-R3 cables, from the Philadelphia suburbs to the Mid-Site substation. The Mid-Site 500 kV substation was identical to the one for the HPOPT 500 kV systems, as described in Section 4.4.1.

4.4 Circuit Analysis

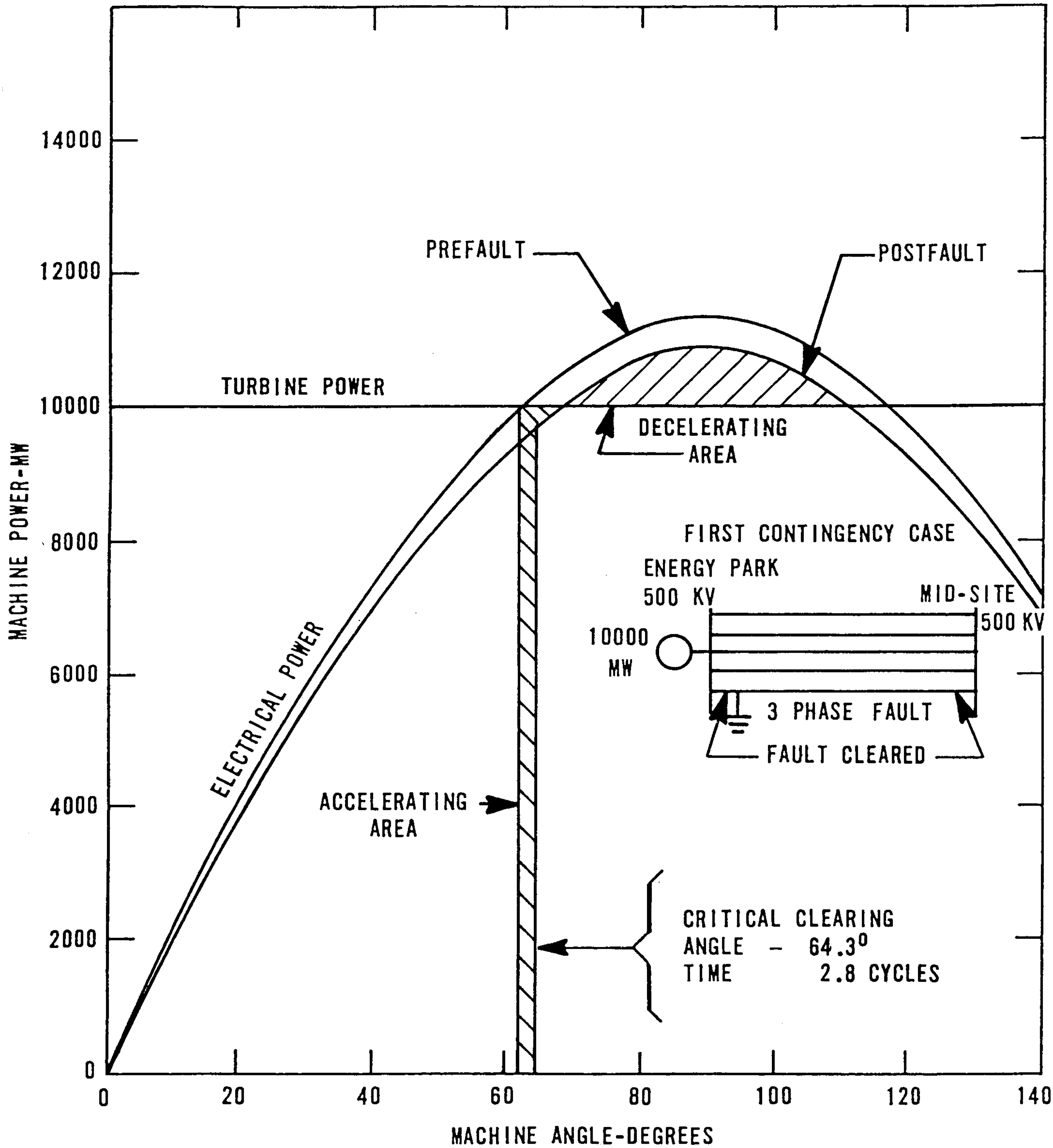
4.4.7 500 kV Aerial/Underground System

4.4.7.1 Compensation (cont'd)

The radial system required 7.5 ohms of series capacitors per circuit, which was 22% of the circuit impedance, to enable the system to meet the transient stability criteria. The series capacitors, which were connected to each circuit at the Energy Park substation, did not cause line voltages above 1.10 p.u. Volts under normal operating conditions.

The network system required 20.2 ohms of series capacitors per circuit, which is 60% of the circuit impedance, to meet the transient stability and network system loading criteria. As in the radial system, the series capacitors were connected to each circuit at the Energy Park substation.

4.4.7.2 Transient Stability. Both the radial and network systems required series capacitors to remain stable following a three-phase fault. The critical clearing times for the two configurations were 2.8 and 11.5 cycles, respectively. The power angle curve for the radial system is shown in Figure 4-26.



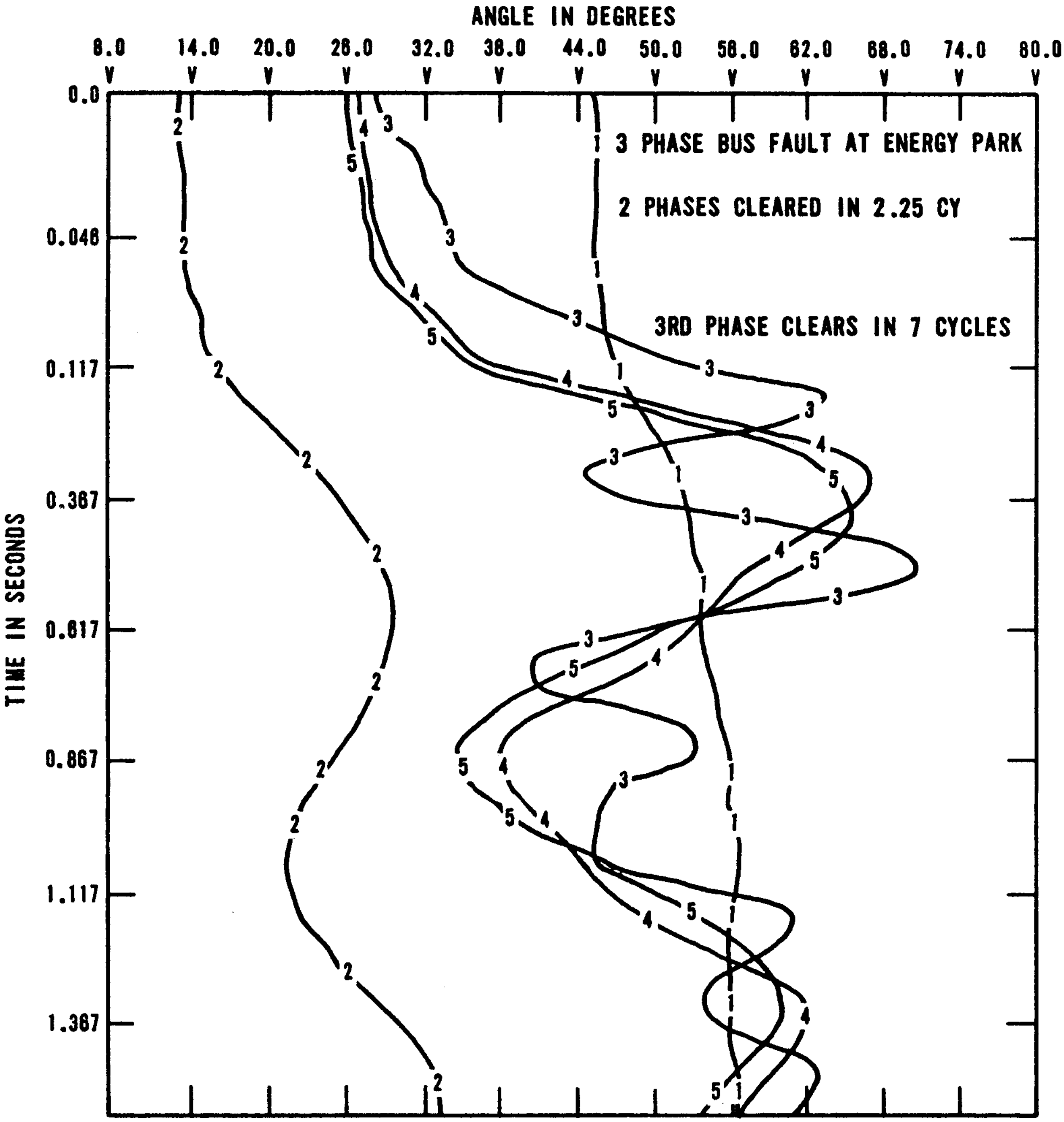
POWER ANGLE CURVE
500KV AERIAL/UNDERGROUND SYSTEM
5 LINES IN PARALLEL

FIG. 4-26

4.4.7.2 Transient Stability (cont'd)

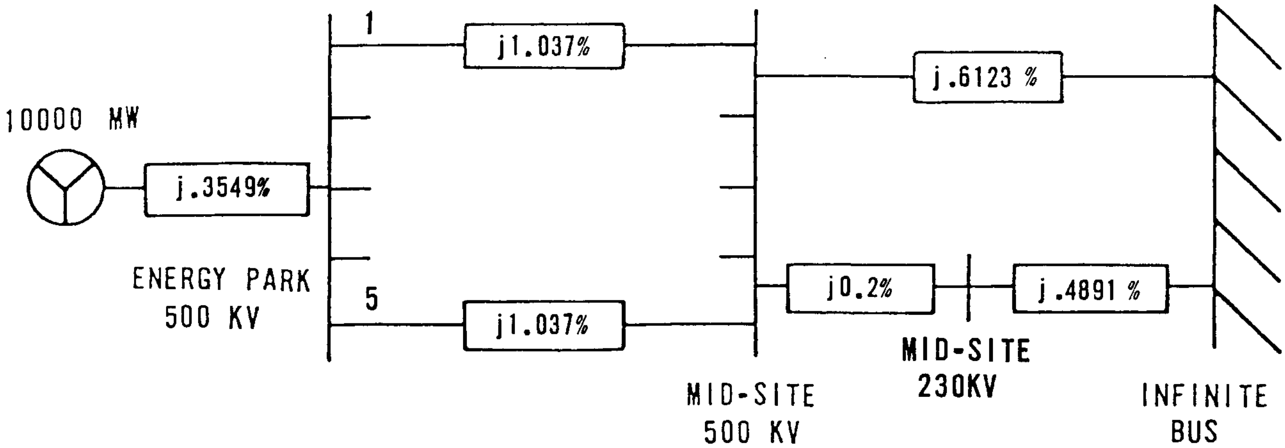
The Transient Stability computer program[2] was used to make a more detailed analysis of the radial configuration. Figure 4-27 shows that the system remained stable for a three-phase fault with delayed clearing due to a single-pole stuck breaker. The generators that are represented in Figure 4-27 are the same as those described in Section 4.4.5.2.

4.4.7.3 Short Circuit Duty. The fault duties are shown in Table 4-3. Figure 4-28 shows the short circuit impedance diagrams.

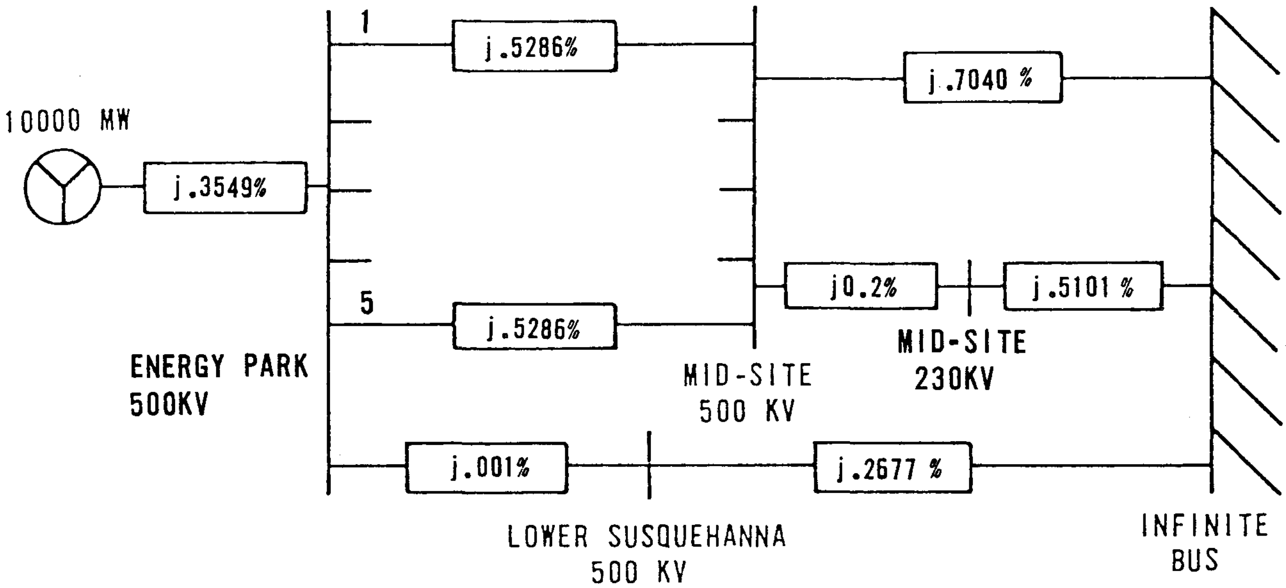


SYMBOL	BUS	NAME
1	31	KEYSTONE 500
2	35	LIMERICK 500
3	999	ENERGY P 500
4	999	ENERGY P 500
5	999	ENERGY P 500

GENERATOR SWING CURVES
500KV AERIAL/UNDERGROUND SYSTEM
5 LINES IN PARALLEL
FIG. 4-27



RADIAL SYSTEM



NETWORK SYSTEM

NOTE: IMPEDANCES ARE IN PERCENT ON A 100 MVA BASE

SHORT CIRCUIT DIAGRAMS
500 KV AERIAL/UNDERGROUND SYSTEM
5 LINES IN PARALLEL

FIG. 4-28

REFERENCES

1. "Power Flow Program", Philadelphia Electric Company.

2. "Power System Stability Program", Philadelphia Electric Company.

3. "Network Fault Analysis Program", Philadelphia Electric Company.

4. E. W. Kimbark, Power System Stability, Volume I, New York, John Wiley & Sons, Inc., 1967.

5. E. W. Kimbark, Direct Current Transmission, Volume I, New York, John Wiley & Sons, Inc., 1971.

5. SUBSTATIONS AND COMPENSATION

5.1 General Description

Energy Park and Mid-Site Substations are the terminal substations for each of the transmission systems being studied. These systems differ from one another with respect to voltage, number of lines, ampacity, fault currents, etc. Therefore, the substations vary and their cost must be included since they are an integral part of each system. Substation costs contain all the necessary facilities to normalize each system so that cost comparisons between systems can be made. These costs do not include any connections for network operation, but do include compensation costs for network operation.

5.1.1 Energy Park Substation. The source substation, Energy Park, is the focal point for the output of ten 1000 MW generation units. Each unit is represented by a step-up generator transformer or equivalent on the single line diagrams (Fig. 5-1 through 5-16). This transformer is located at Energy Park Substation in this study. The cost of any other consideration applies equally to all systems.

5.1.2 Mid-Site Substation. The remote substation, Mid-Site, at the load terminal of the transmission corridor, distributes 6500 MW into the Philadelphia Electric Company system at 230 kV and 3500 MW into the PJM Interconnection at 500 kV.

5.1.3 Compensation Stations. Several cable systems require shunt inductive compensation to be distributed along the length of the transmission corridor. In each of these systems, there are Compensation Station locations where the cable is terminated to permit the installation of shunt reactors.

5. SUBSTATIONS AND COMPENSATION (cont'd)

5.2 Design Considerations

Since this study is intended to investigate several schemes to move a large amount of power through a transmission corridor, the primary emphasis is not to develop new concepts in substation technology. Existing concepts have been extrapolated to reasonable limits, for instance, in the areas of ampacity and fault currents. Large load currents can be carried by multiconductors and multipoles per phase; complicated control schemes can reduce large problems to reasonable ones with the use of microprocessors.

5.2.1 Substation Arrangement. The terminal substations employ a breaker and one-half switching scheme. This provides the reliability and switching versatility necessary to maintain load flow for normal and abnormal operating conditions. Bus sectionalizing breakers are provided because of the large quantity of power involved. These breakers reduce the size of the substation area and line elements affected by a breaker malfunction or bus fault.

5.2.2 Bus Construction. All buses are open construction and elevated above grade. The buses are constructed for basic insulation level and maximum fault currents as follows:

System Voltage	BIL	Fault Current
765 kV	2050 kV	62 kA
500 kV	1550 kV	93 kA
230 kV	1050 kV	135 kA

5. SUBSTATIONS AND COMPENSATION

5.2 Design Considerations

5.2.2 Bus Construction (cont'd)

While open-bus construction is used for this study, it does not preclude using gas-insulated bus and equipment. In comparing open construction with gas-insulated equipment, differences in cost will vary with substation voltage and substation location.

Transformer and compensation equipment have reduced BIL and are protected with surge arresters.

5.2.3 Direct Current Technology. Two of the systems studied are direct current cable systems. While the use of dc buses and switching equipment looks very attractive, the equipment and devices to operate a dc power system are not highly developed. For instance, the high current magnitudes involved are considerably beyond today's state-of-the-art dc circuit breaker. Nonetheless, it has been assumed that the technology to build and operate a direct current switching substation will advance and will be practical.

5.2.4 Single Line Diagrams. Substation single line diagrams for each transmission system are shown in Figures 5-1 through 5-15, with the single exception of the 345 kV Resistive Cryogenic Cable system. These are simplified diagrams and do not show all primary equipment. All breakers are

5.2 Design Considerations

5.2.4 Single Line Diagrams (cont'd)

indicated, but only those disconnecting switches essential to switching paired lines are shown. Devices for system protection, instrumentation, safety grounding, etc., are not included on these diagrams. Figure 5-16 is a legend to identify the primary equipment shown.

5.3 Ampacity

Concentrating 10,000 MW of capacity in a single location produces current magnitudes greater than that to which we are normally accustomed. The worst conditions occur for the superconducting cable systems where there are only three lines and the system voltage is 230 kV ac or 300 kV dc. Emergency line currents are 25,000 A on the 300 kV dc system, and 18,827 A on the 230 kV ac system.

Multitubular conductors are required extensively for substation conductors. Spacers and head clamps to support and hold some of these conductors, while not standard products, can be designed and fabricated to fulfill the needs.

AC circuit breakers and disconnecting switches for the large currents can be built up from modular elements into ganged, multipole-per-phase devices. This approach makes high current devices conceivable and provides a reasonable basis for cost estimating.

5.3 Ampacity (cont'd)

The substation configurations are arranged to limit normal loading in a supply or line section to 2000 MW, where practical. Some of the systems cannot be handled within this limitation, so exceptions are made for three- and four-line systems. Sources are matched with loads in individual elements to keep loading in conductor segments to a minimum.

5.4 Fault Currents

Maximum fault currents for the three ac voltage classifications are listed in Section 5.2.2. Buses and equipment that can sustain the mechanical forces associated with these high fault currents are not as much concern as is a circuit breaker with a capability to interrupt the fault currents. Unfortunately, breaker poles cannot be paralleled to increase interrupting capability as can be done with ampacity. Current limiting devices (CLD's) are not being used because the problem has been dealt with.

5.4.1 765 kV and 500 kV. Today, 63 kA interruption is a reality at 765 kV and 500 kV. Such existing breaker designs have current ratings generally smaller than what is required in this study. It has been assumed that the necessary interruption capabilities will be developed along with increased ampacity.

5.4 Fault Currents (cont'd)

5.4.2 230 kV. A breaker that can interrupt 135 kA is viewed with less optimism. At 230 kV, 80 kA interruption is available now. If the substations are separated into halves under fault conditions, then the maximum fault current to be interrupted is approximately 80 kA. Interruption of faults for both 230 kV superconducting systems is based on sequentially tripping selected breakers to separate the system, then followed by breaker trippings to isolate the fault.

Sequential breaker operation adds one half-cycle to fault clearing time. This is sufficiently fast to maintain system stability.

5.5 Cost Estimates

Substation cost estimates are shown for each transmission system and are listed in Tables 5-1 through 5-15. Each substation estimate is broken down into major cost categories. The basic cost does not include any compensation; compensation costs are itemized in the tables separately since they can vary with radial or network system operation.

5.5.1 Line Terminations. Cable terminal facilities require special treatment since cable systems have specialized terminal equipment unique to the cable. The line terminations are considered to be a part of the line, and the costs are included with the cable, not with the substation. In the same manner, the aerial to underground transition in the 500 kV Aerial/Underground System is not included in the substation costs.

5.5 Cost Estimates (cont'd)

5.5.2 Paired Lines. On the two systems with the largest number of lines, the lines are paired and each pair operates as a single circuit. System requirements can still be met with this arrangement. The saving in substation cost is obvious. Switching facilities permit line segments to be isolated and proper line compensation to be maintained.

5.5.3 Contingency. A 10% overall contingency is used generally. This is applied to cover unanticipated rises in the cost of materials and services, and to cover small items which are too minute to detail.

5.6 Line Compensation

Varying amounts of inductive and/or capacitive compensation are required for the different cable systems (Table 4-2). In some cases compensation is distributed along the lines, in others it is concentrated at the extremities.

5.6.1 Reactors. Both shunt and series reactors are utilized to provide line compensation. In six of the eight systems requiring shunt reactors, the reactors are distributed among the terminal substations and compensation stations. A constant cost per KVAR cannot be applied to determine shunt reactor compensation costs because of the wide range in sizes and the varied ways that reactors are dispersed for the different systems.

5. SUBSTATIONS AND COMPENSATION

5.6 Line Compensation

5.6.1 Reactors (cont'd)

Where series reactors are specified, it is assumed they are installed at the Energy Park terminal. There are nine systems requiring series reactors. Of these, six have compensation stations and the reactance could be broken into smaller quantities and distributed without significant additional cost.

For the remaining three that do not have compensation stations, the cost penalty to spread the reactance would be an appreciable addition to the compensation cost.

5.6.2 Capacitors.

Series capacitors are specified on four systems. Here again, they are assumed to be installed at Energy Park. Distributing the capacitance along the lines would increase capacitor costs because none of the four systems has existing compensation stations.

Very large currents are involved in the 230 kV superconducting systems. Assembling modules in series and parallel combinations to carry the current and give the required compensation results in monstrous capacitor installations. The largest is the 230 kV superconducting rigid case with three lines, where each phase has 10.92 ohms of capacitance and carries 18,827 Amperes. This capacitor installation, complete with by-pass switching facilities, occupies approximately 16.2 ha.(40 acres).

5.7 Direct Current Systems

A different substation configuration is being used for each of the dc systems. The 300 kV dc system is monopolar, and dc switching facilities, including dc circuit breakers, are used at each terminal (Figure 5-14).

The 600 kV dc system is bipolar. It uses the conventional arrangement with conversion equipment and transmission line operating as a unit (Figure 5-7). No dc breakers are used.

5.7.1 300 kV DC. Extrapolating today's state-of-the-art dc breakers to the very high carry and interrupt currents required for this system is an optimistic point of view. Assuming the technology will exist, the dc switching substation is more economical than alternate schemes employing ac switching substations, increased conversion capacity, and/or an additional transmission line.

The rectifiers and generators are operated as a unit. This provides for maintenance periods coincident with the nuclear generation units. Extra inverter capacity is necessary at Mid-Site to maintain the required contingency capacity. The inverters at Mid-Site are rated 2000 MW per terminal.

5.7.2 600 kV DC. This system is a bipolar system, ±600 kV dc, which operates similarly to several present-day installations. A conversion capacity greater than the nominal 10,000 MW is required to supply load during first contingency fault conditions. Both the Energy Park and Mid-Site conversion terminals are rated 2857 MW per terminal.

5. SUBSTATIONS AND COMPENSATION

5.7 Direct Current Systems (cont'd)

5.7.3 Electrostatic and Magnetic Field Effects. No attempt has been made to evaluate and estimate the cost to compensate for the physiological and psychological effects of the static and magnetic fields resulting from the high dc currents in the substation conductors. Valve halls and other conversion equipment are shielded in accordance with present-day practice.

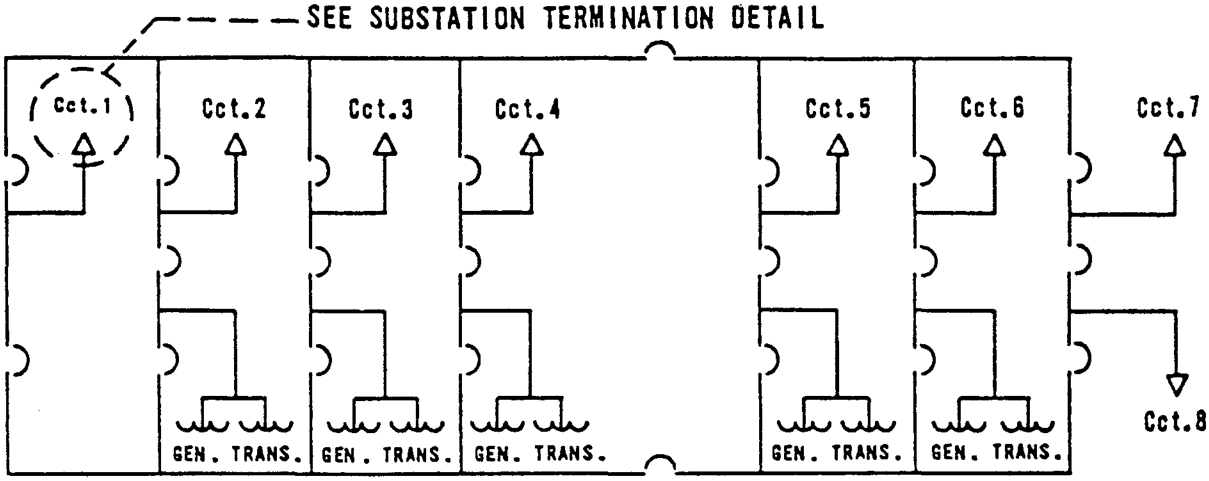
5.8 Communications

The transfer and exchange of intelligence between terminals, compensation stations, etc., is an important factor in the operation of this high-capacity transmission corridor. Automatic protective relaying schemes, supervisory control of equipment, telemetering, etc., must have a secure and reliable communication link. For these functions, two independent links are provided. A microwave system is the primary link; a private cable system is the back-up link.

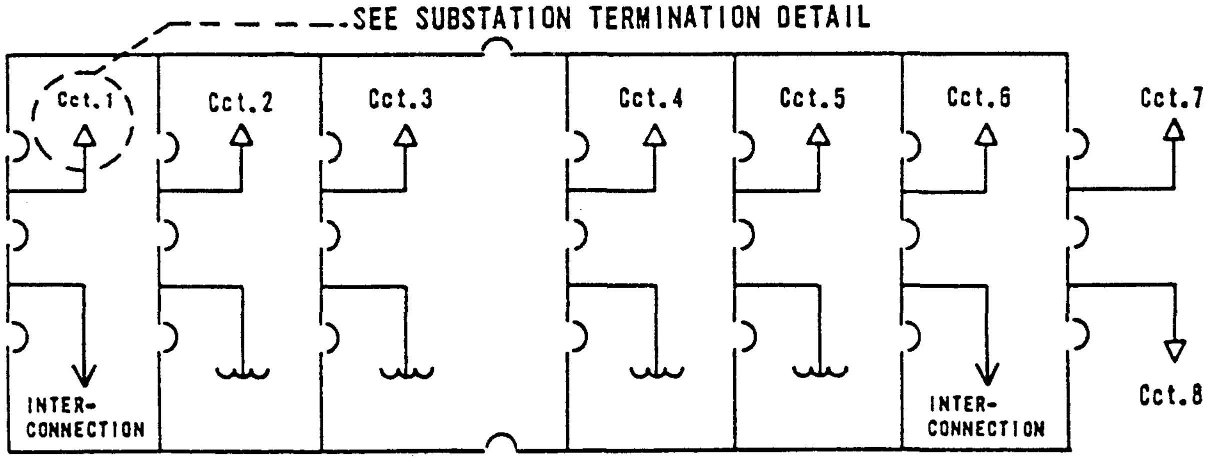
The microwave link consists of terminals at Energy Park and Mid-Site Substations with three repeater stations between them. Repeater stations can be located at any strategic place; however, repeaters were placed at the Compensation Stations in those plans that have compensation stations because of the necessity to include them in the exchange of intelligence.

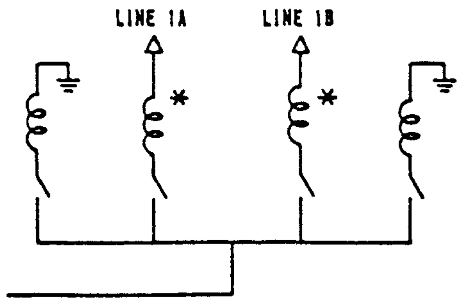
A private telephone cable system is the independent back-up link. The cable is buried in the transmission right-of-way. These two systems complement each other because they are not subject to the same types of failures.

ENERGY PARK 500 KV SUBSTATION



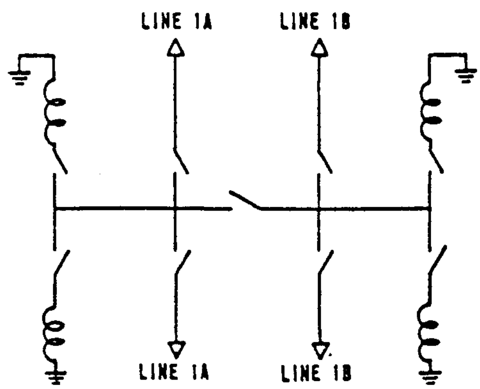
MID-SITE 500 KV SUBSTATION





SUBSTATION TERMINATION DETAIL

*WHERE APPLICABLE



COMPENSATION STATION DETAIL

FIGURE 5-1

SINGLE LINE DIAGRAM

500 KV HPOPT CELLULOSE-INSULATED CABLE
8 CIRCUITS - 16 LINES

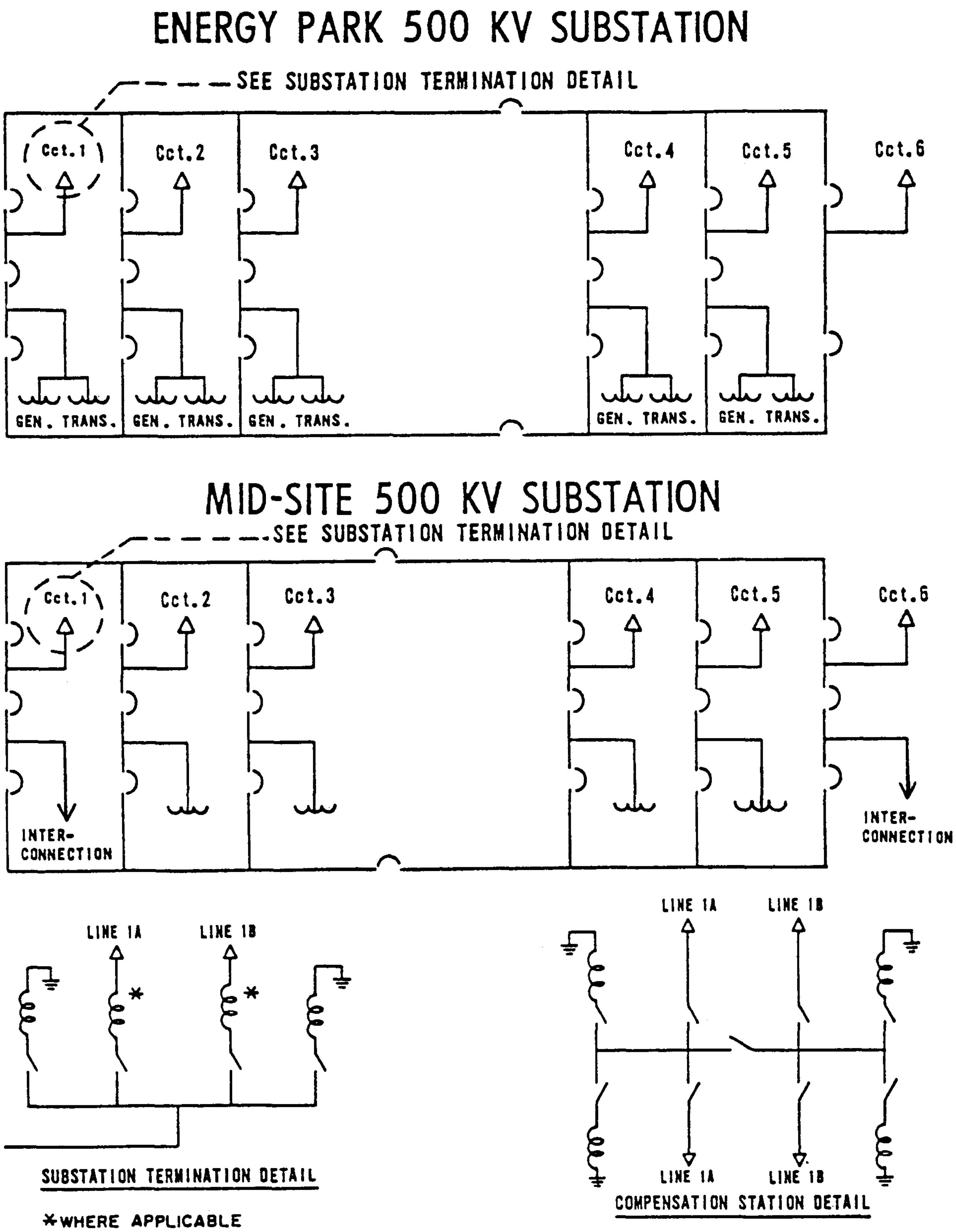
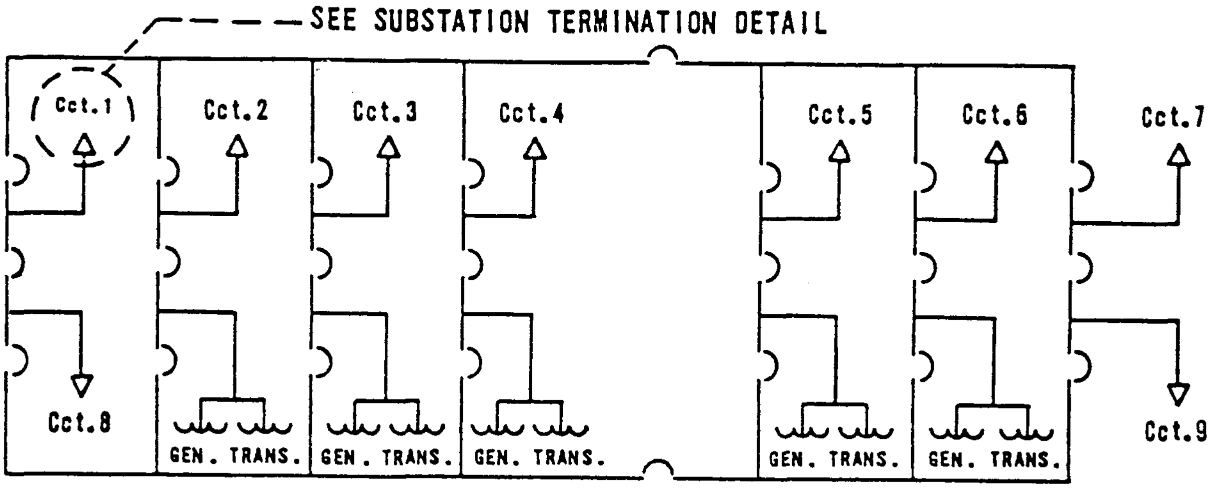


FIGURE 5-2

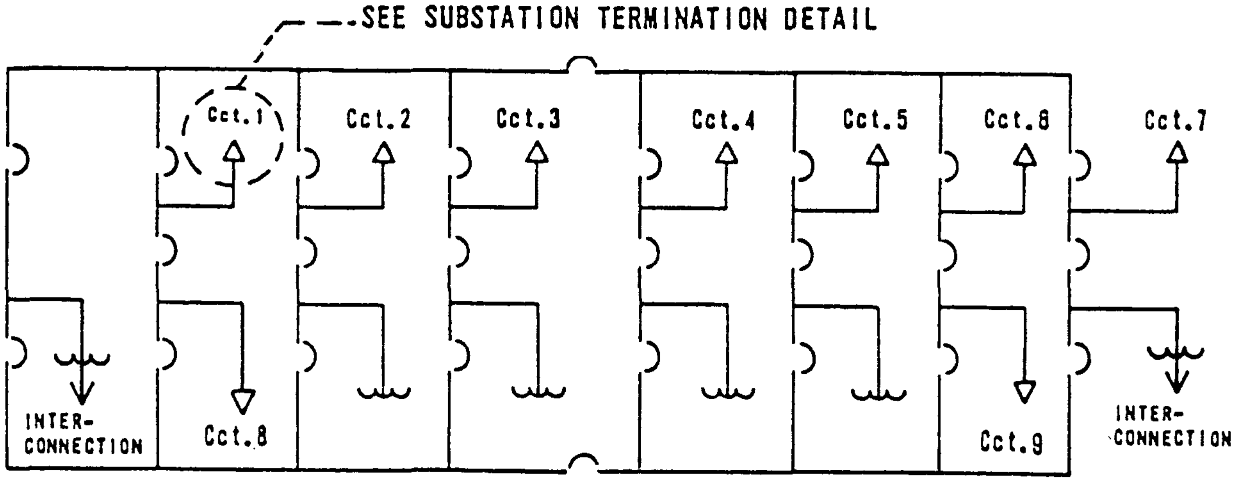
SINGLE LINE DIAGRAM

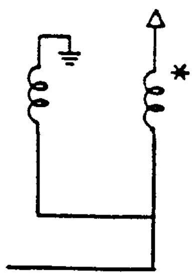
500 KV HPOPT PPP-INSULATED CABLE
6 CIRCUITS — 12 LINES

ENERGY PARK 765 KV SUBSTATION



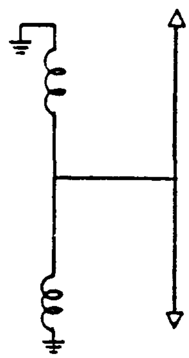
MID-SITE 765 KV SUBSTATION





SUBSTATION TERMINATION DETAIL

*WHERE APPLICABLE



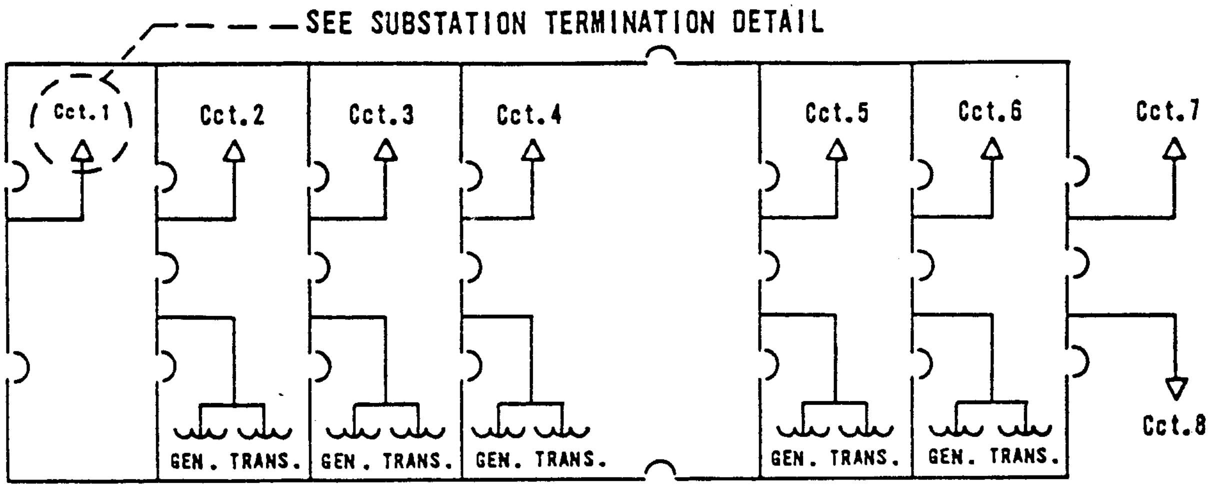
COMPENSATION STATION DETAIL

FIGURE 5-3

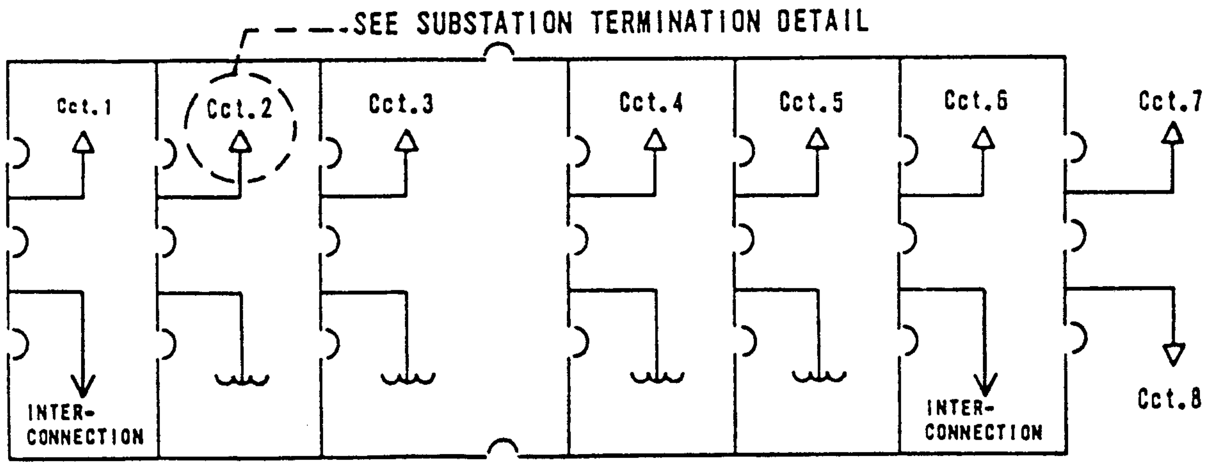
SINGLE LINE DIAGRAM

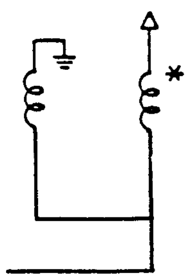
765 KV HPOPT PPP-INSULATED CABLE 9 LINES

ENERGY PARK 500 KV SUBSTATION



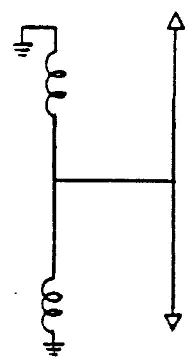
MID-SITE 500 KV SUBSTATION





SUBSTATION TERMINATION DETAIL

*WHERE APPLICABLE



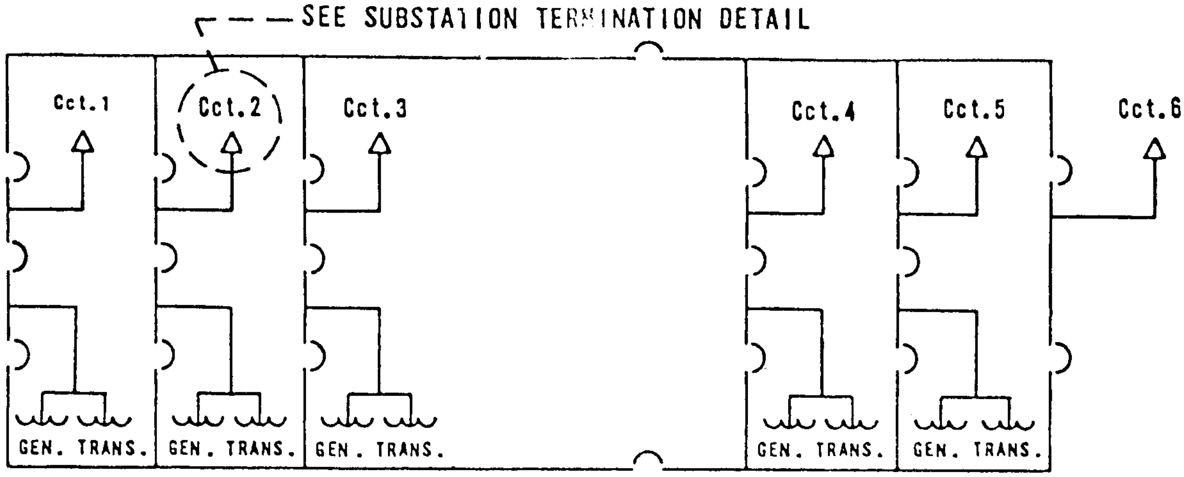
COMPENSATION STATION DETAIL

FIGURE 5-4

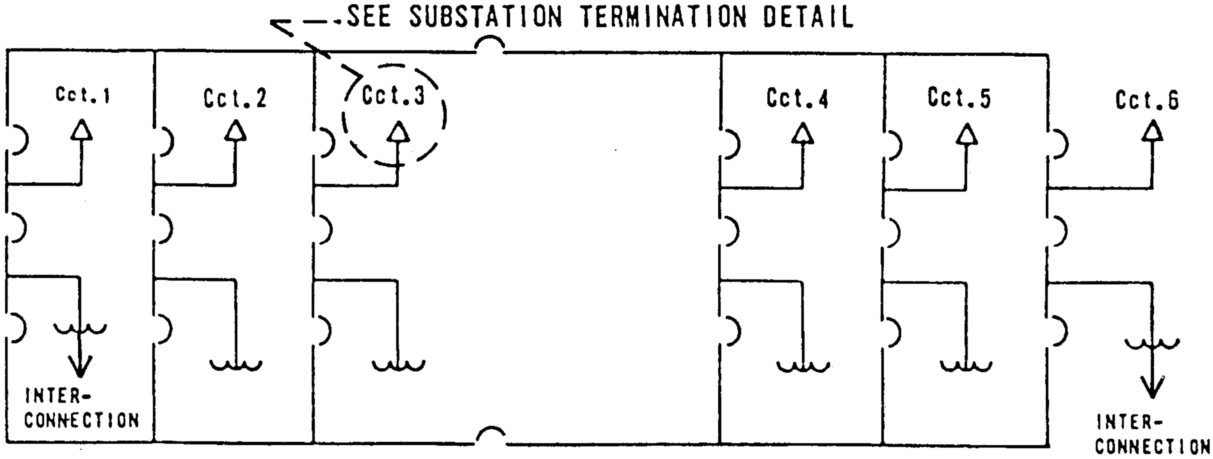
SINGLE LINE DIAGRAM

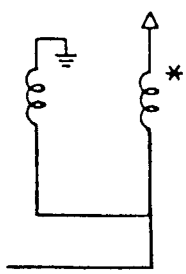
500 KV FORCE-COOLED HPOPT PPP-INSULATED CABLE 8 LINES

ENERGY PARK 765 KV SUBSTATION



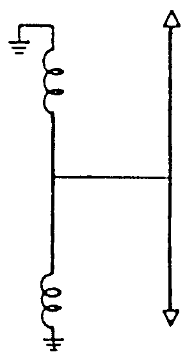
MID-SITE 765 KV SUBSTATION





SUBSTATION TERMINATION DETAIL

*WHERE APPLICABLE



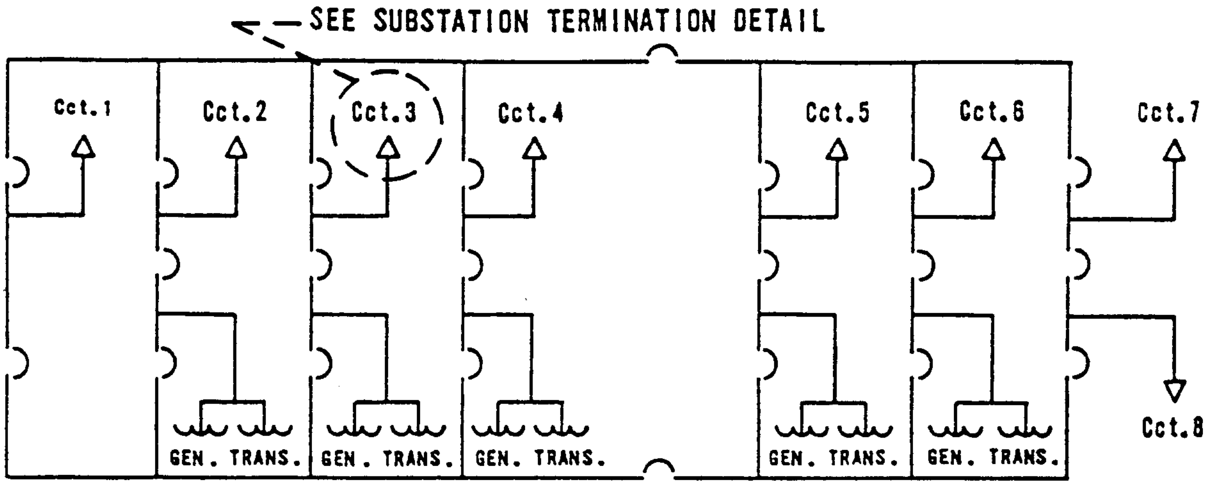
COMPENSATION STATION DETAIL

FIGURE 5-5

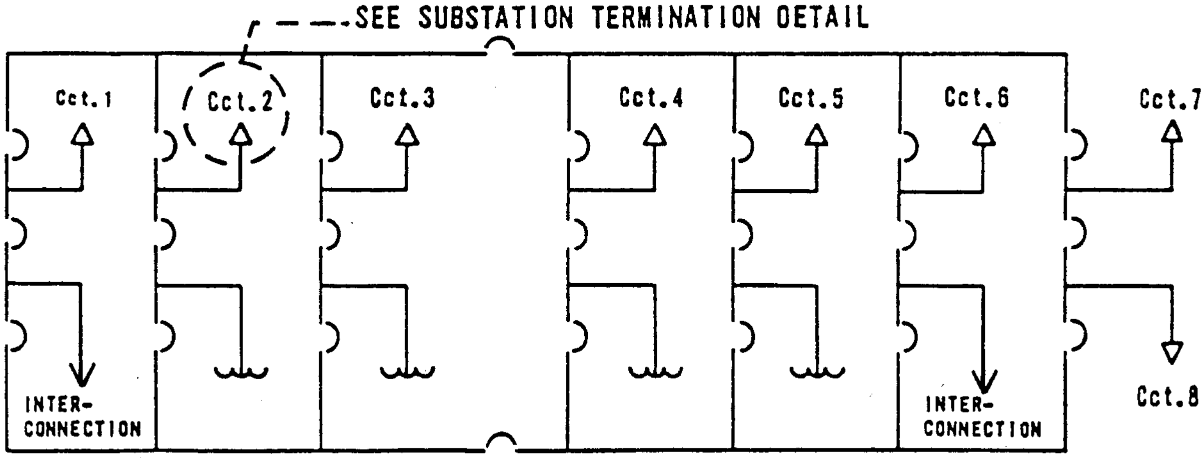
SINGLE LINE DIAGRAM

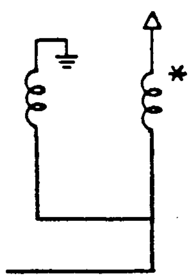
765 KV FORCE-COOLED HPOPT PPP-INSULATED CABLE
6 LINES

ENERGY PARK 500 KV SUBSTATION



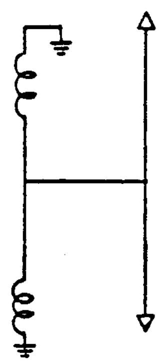
MID-SITE 500 KV SUBSTATION





SUBSTATION TERMINATION DETAIL

*WHERE APPLICABLE



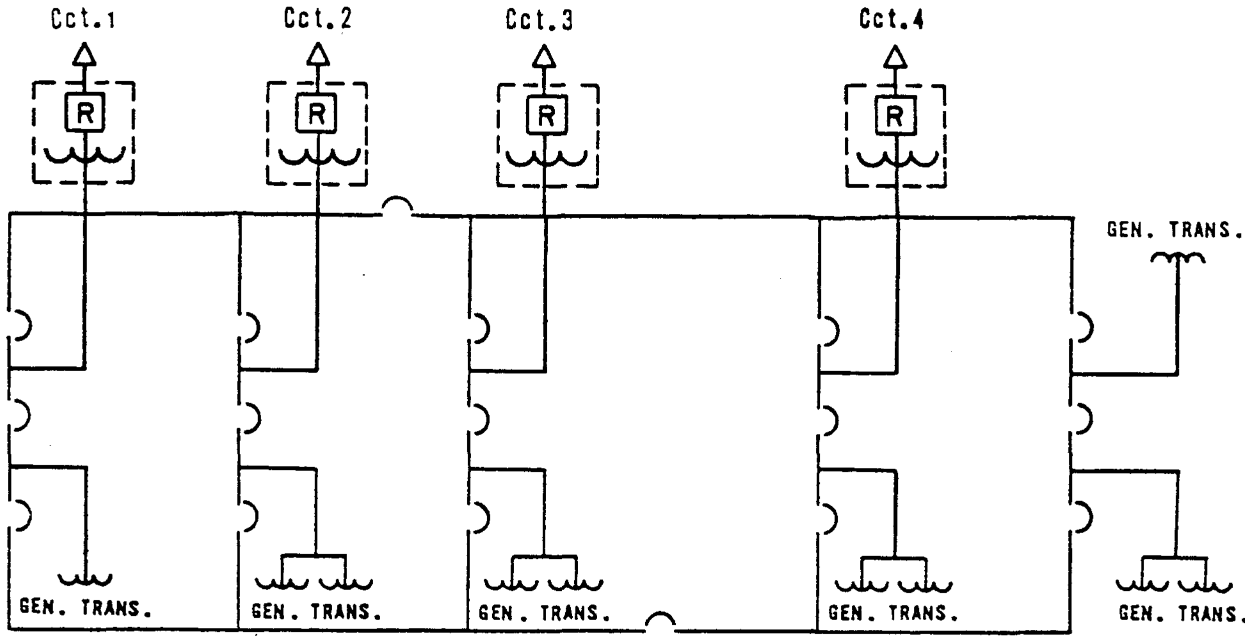
COMPENSATION STATION DETAIL

FIGURE 5-6

SINGLE LINE DIAGRAM

500 KV AC SELF-CONTAINED OIL-FILLED CABLE
8 LINES

ENERGY PARK 600 KV DC/230 KV AC SUBSTATION



MID-SITE 600 KV DC/230 KV AC SUBSTATION

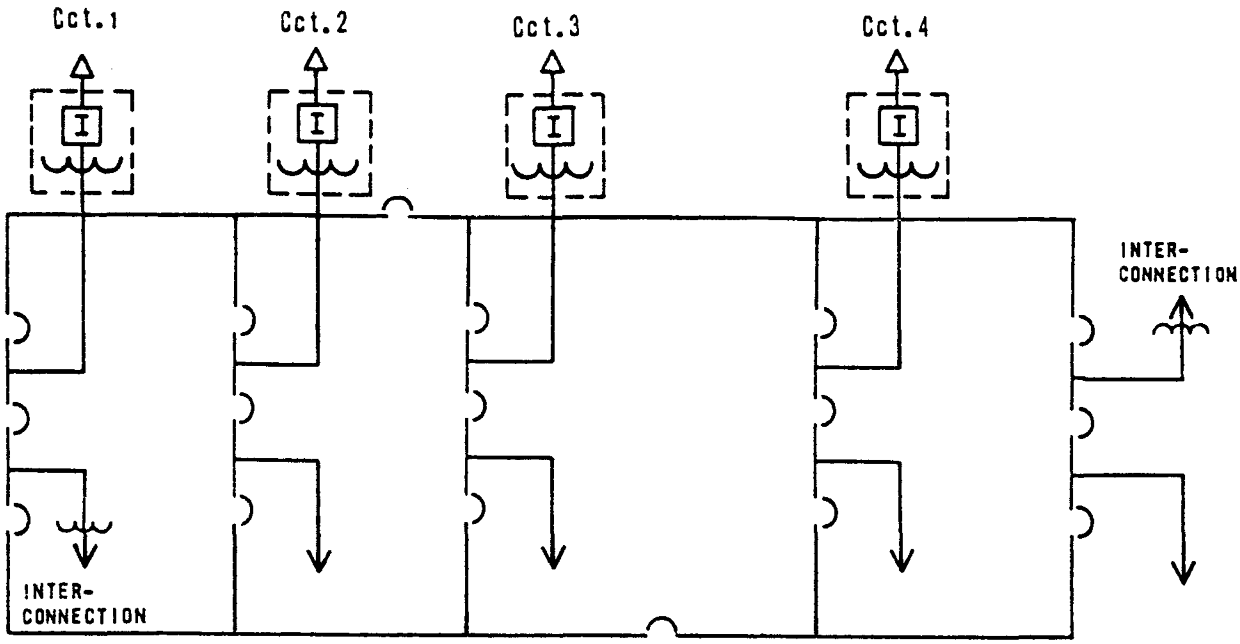
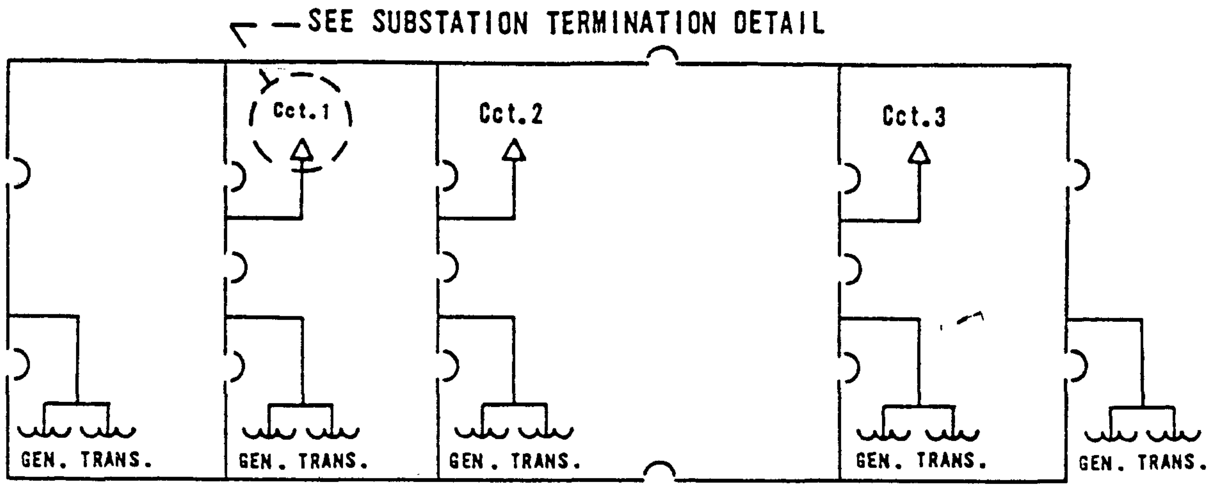


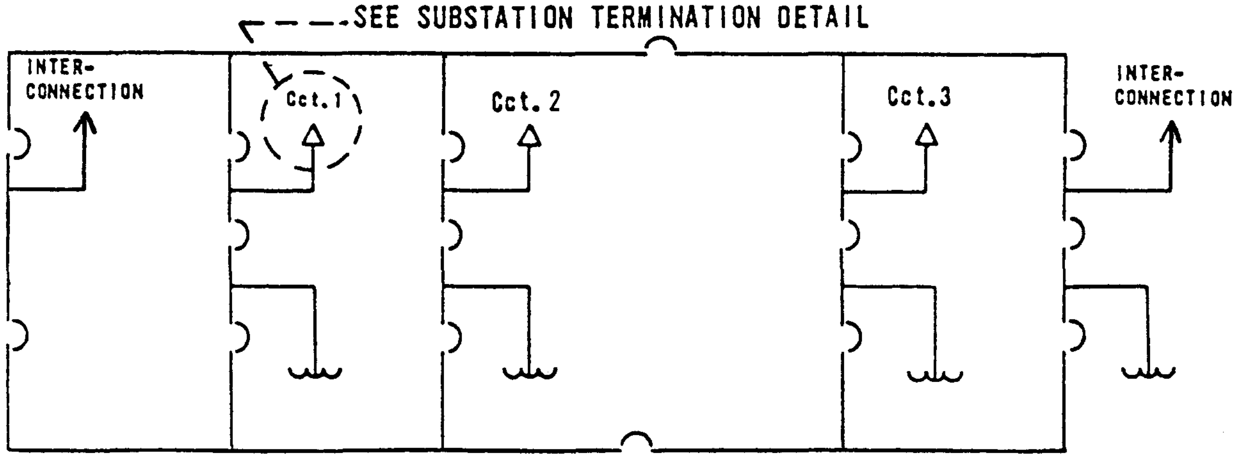
FIGURE 5-7
SINGLE LINE DIAGRAM

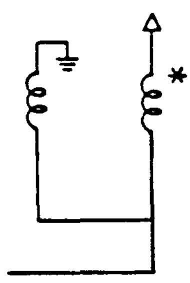
600 KV DC SELF-CONTAINED OIL-FILLED CABLE
4 LINES

ENERGY PARK 500 KV SUBSTATION



MID-SITE 500 KV SUBSTATION





SUBSTATION TERMINATION DETAIL

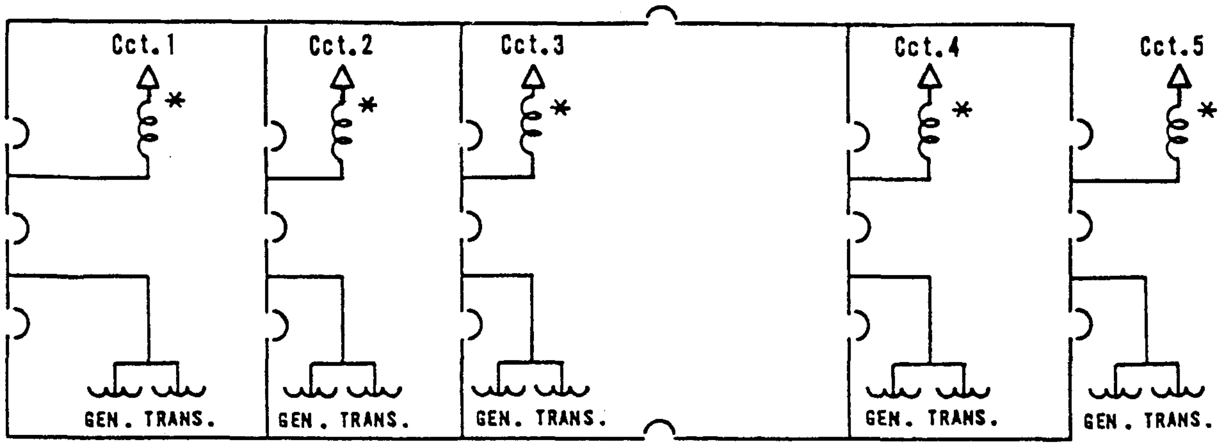
*WHERE APPLICABLE

FIGURE 5-8

SINGLE LINE DIAGRAM

500 KV SINGLE-PHASE SF_6, GITL, RIGID SYSTEM 3 LINES

ENERGY PARK 500 KV SUBSTATION



*WHERE APPLICABLE

MID-SITE 500 KV SUBSTATION

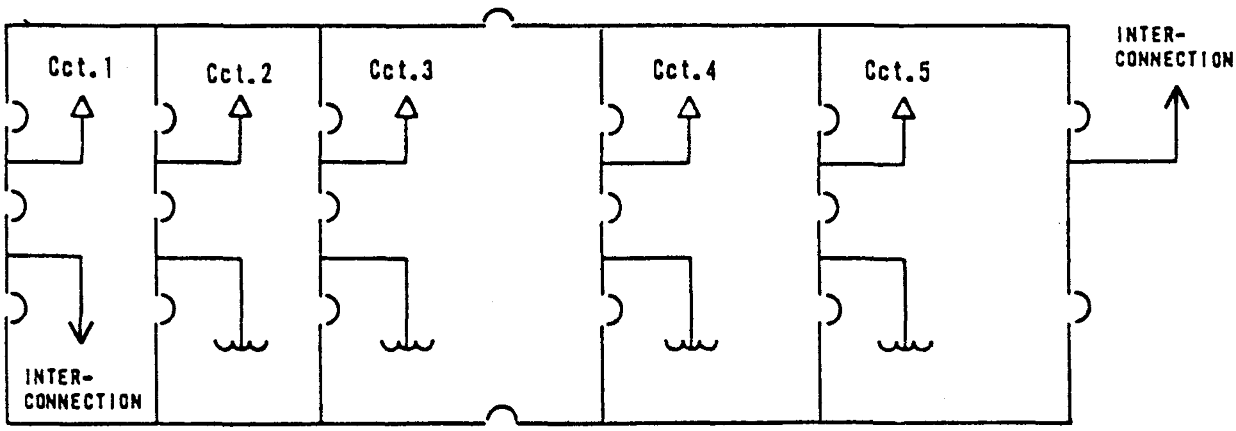
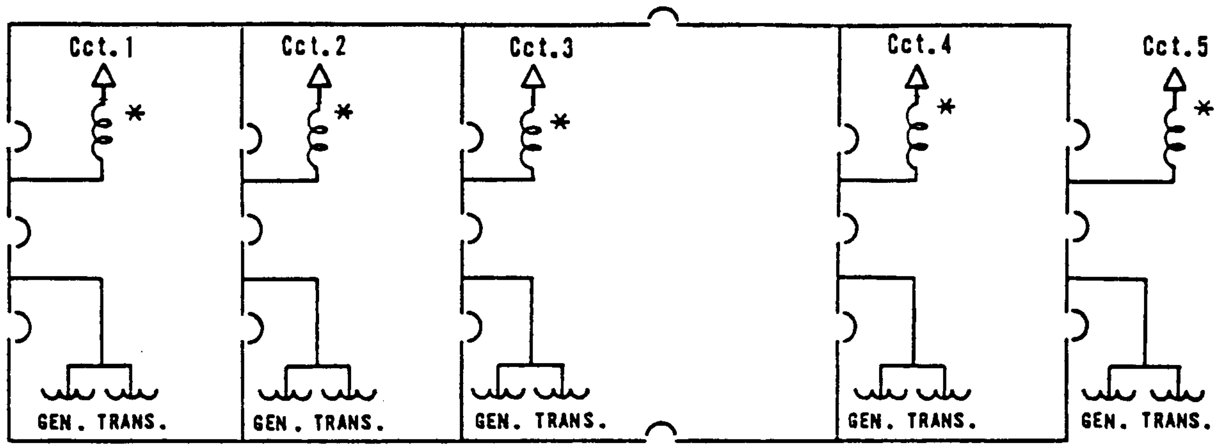


FIGURE 5-9

SINGLE LINE DIAGRAM

500 KV SINGLE-PHASE SF_6, GITL, FLEXIBLE SYSTEM 5 LINES

ENERGY PARK 500 KV SUBSTATION



*WHERE APPLICABLE

MID-SITE 500 KV SUBSTATION

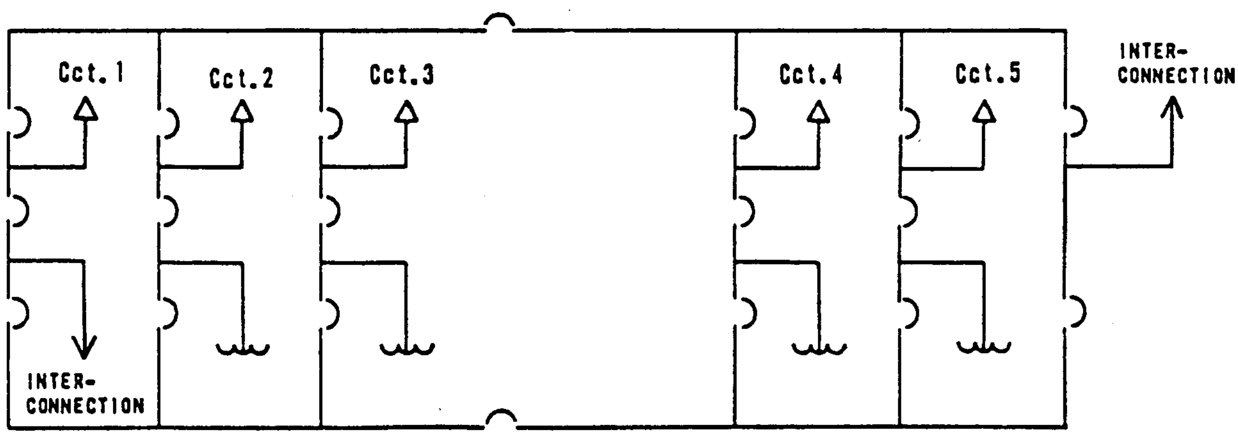
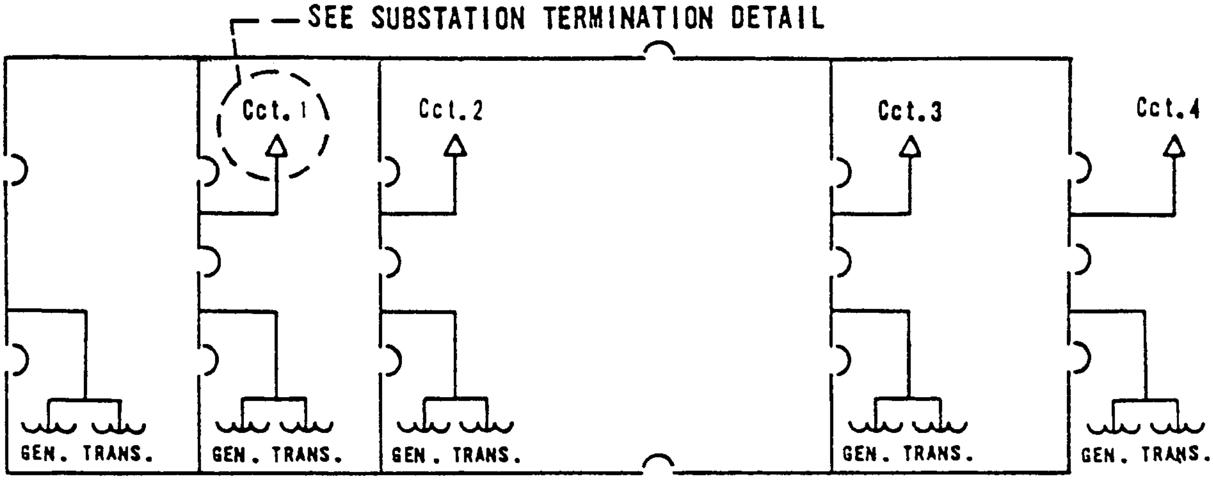


FIGURE 5-10

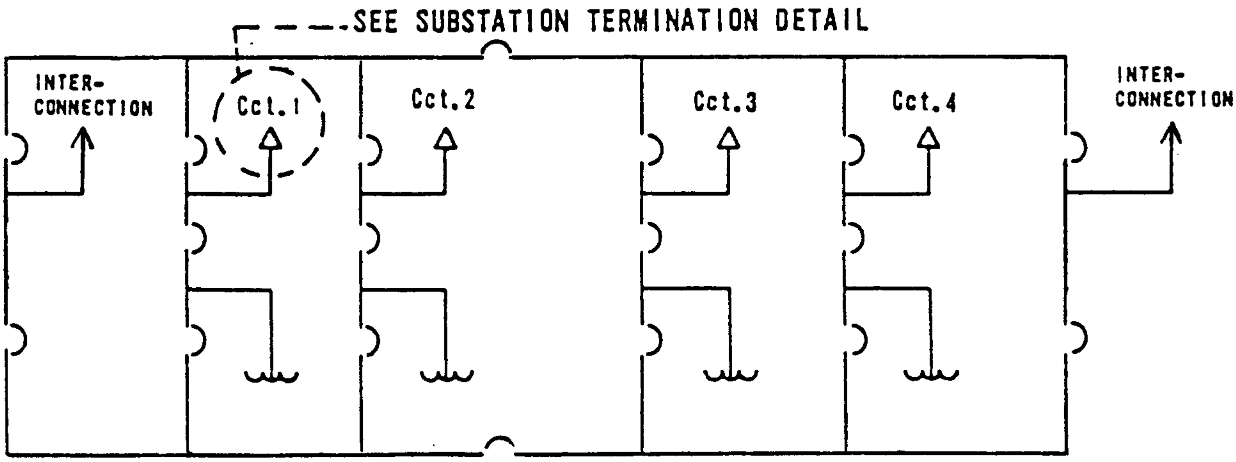
SINGLE LINE DIAGRAM

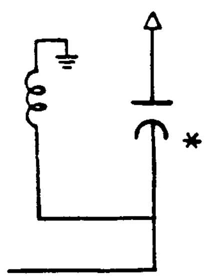
500 KV THREE-PHASE SF_6, GITL, RIGID SYSTEM 5 LINES

ENERGY PARK 500 KV SUBSTATION



MID-SITE 500 KV SUBSTATION





SUBSTATION TERMINATION DETAIL

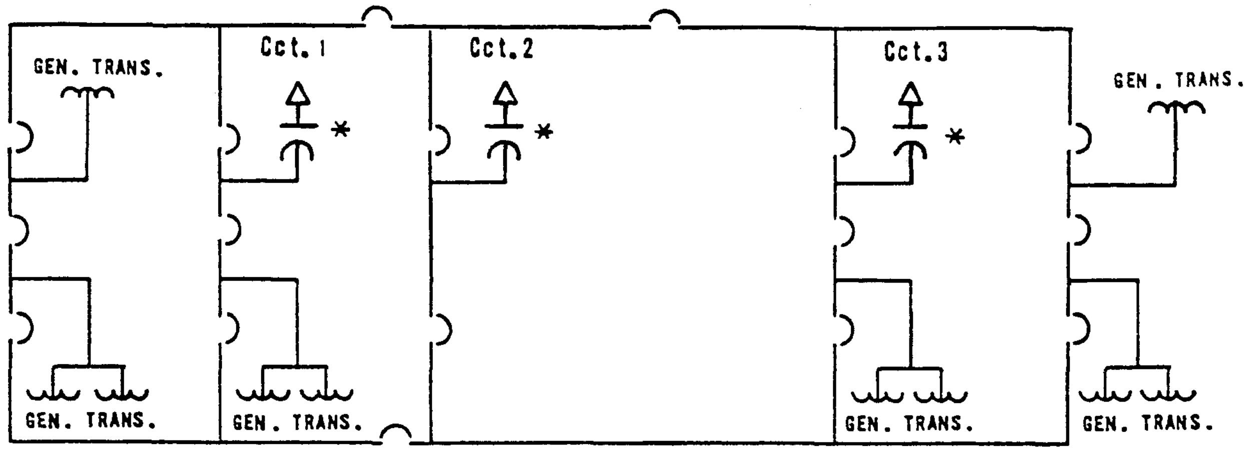
*WHERE APPLICABLE

FIGURE 5-11

SINGLE LINE DIAGRAM

500 KV RESISTIVE CRYOGENIC CABLE
4 LINES

ENERGY PARK 230 KV SUBSTATION



*WHERE APPLICABLE

MID-SITE 230 KV SUBSTATION

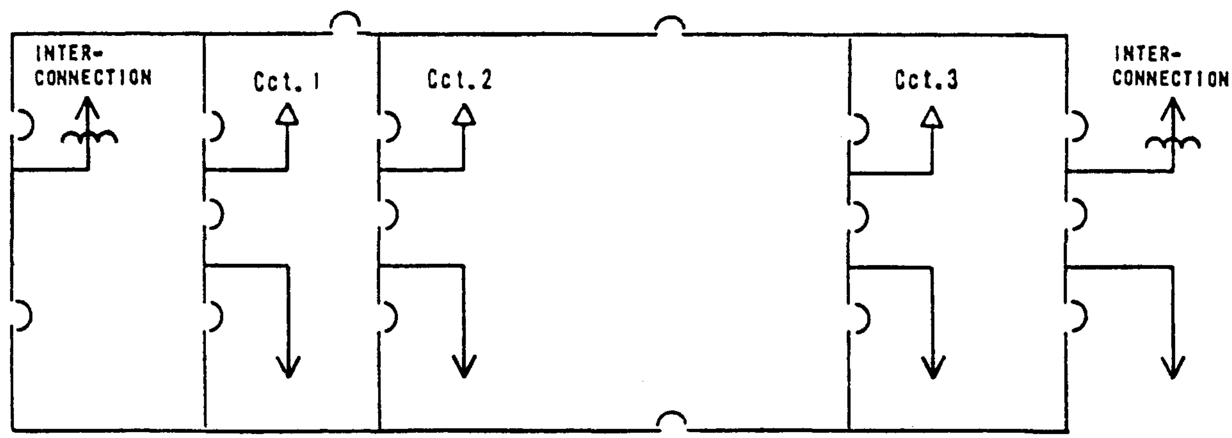
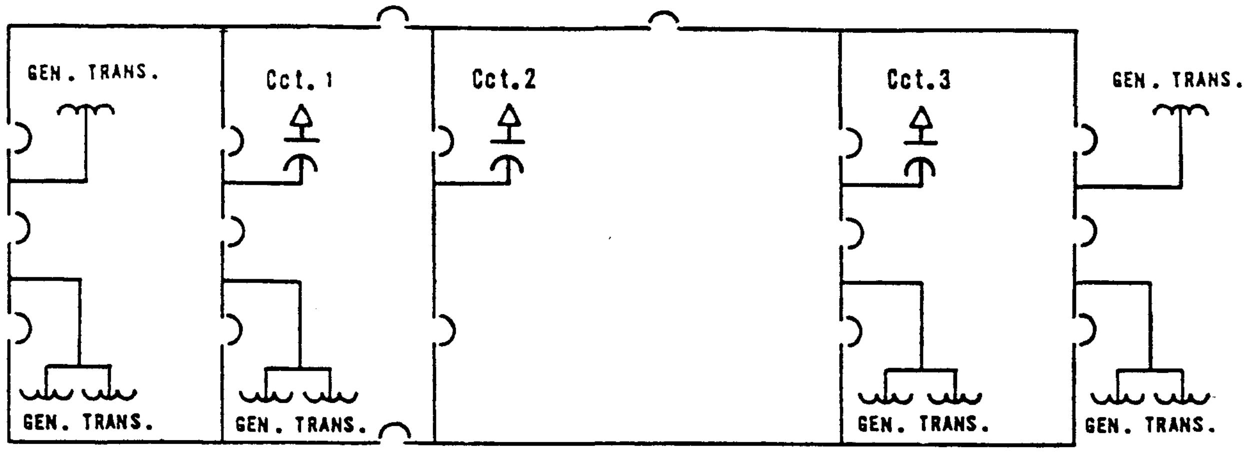


FIGURE 5-12

SINGLE LINE DIAGRAM

230 KV SUPERCONDUCTING CABLE
3 LINES

ENERGY PARK 230 KV SUBSTATION



MID-SITE 230 KV SUBSTATION

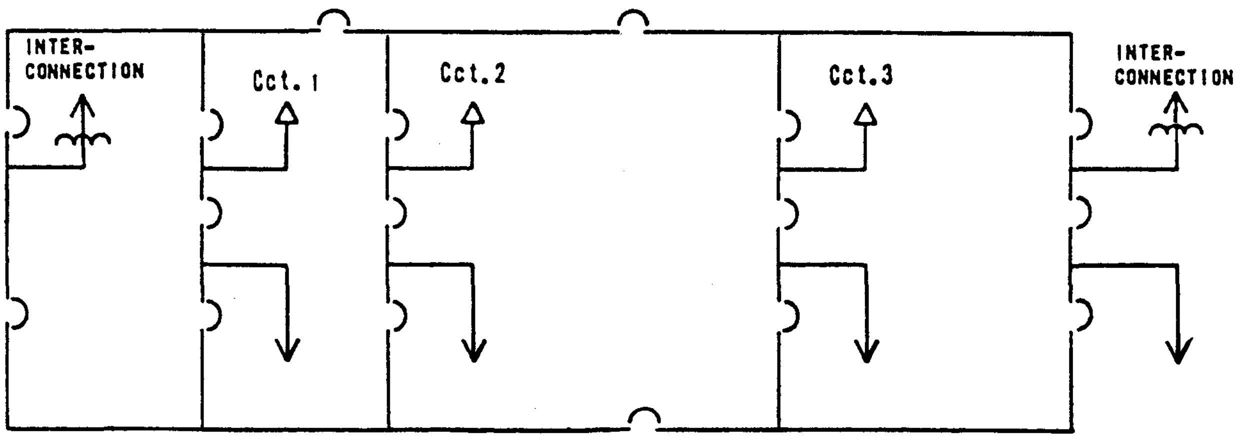
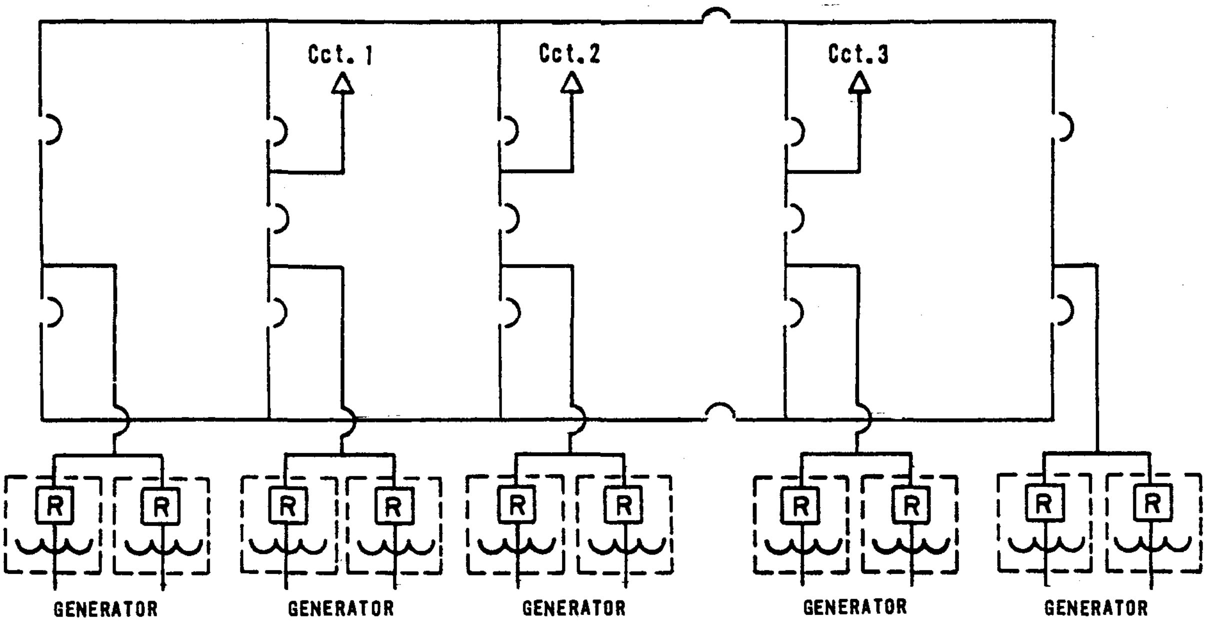


FIGURE 5-13
SINGLE LINE DIAGRAM

230 KV SUPERCONDUCTING CABLE, RIGID SYSTEM
3 LINES

ENERGY PARK 300 KV DC SUBSTATION



MID-SITE SUBSTATION

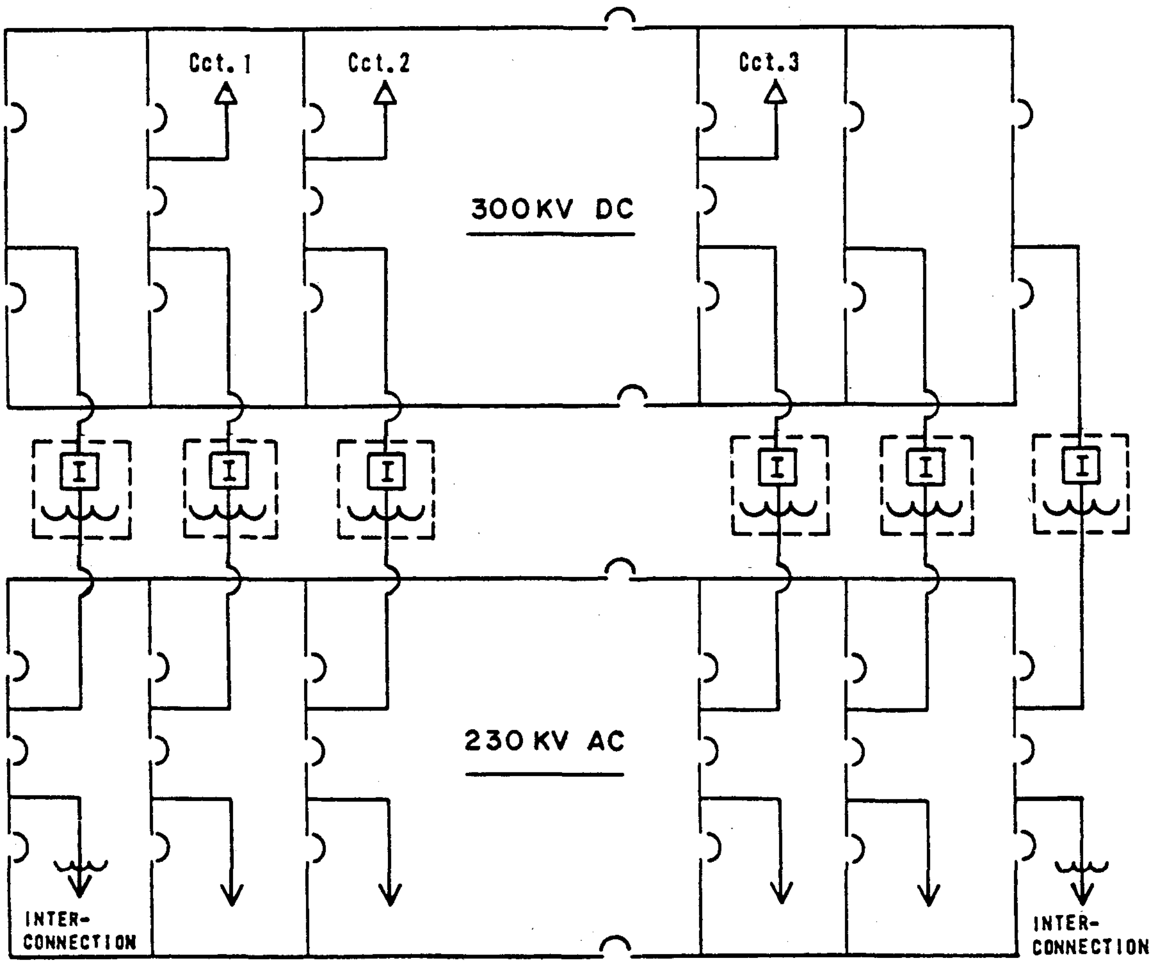
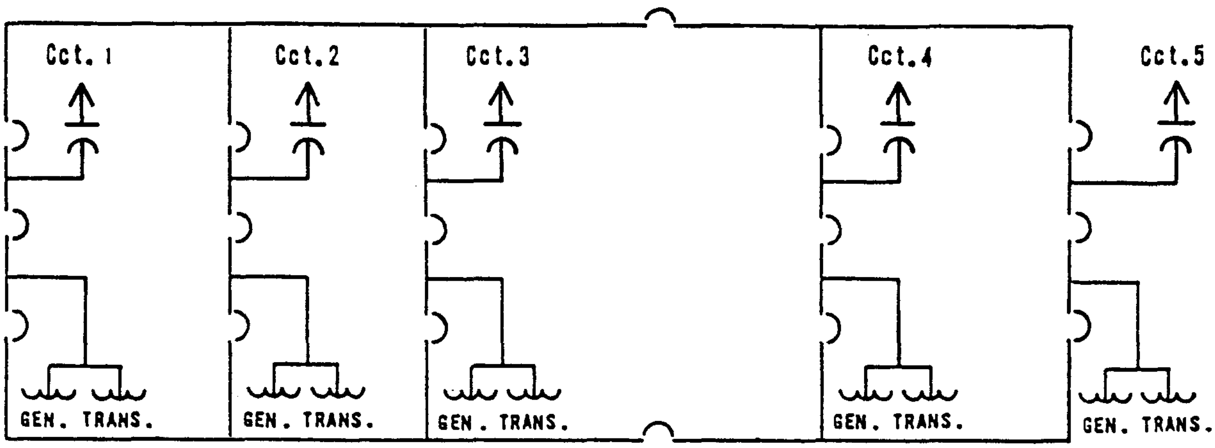


FIGURE 5-14

SINGLE LINE DIAGRAM

300 KV DC SUPERCONDUCTING CABLE
3 LINES

ENERGY PARK 500 KV SUBSTATION



MID-SITE 500 KV SUBSTATION

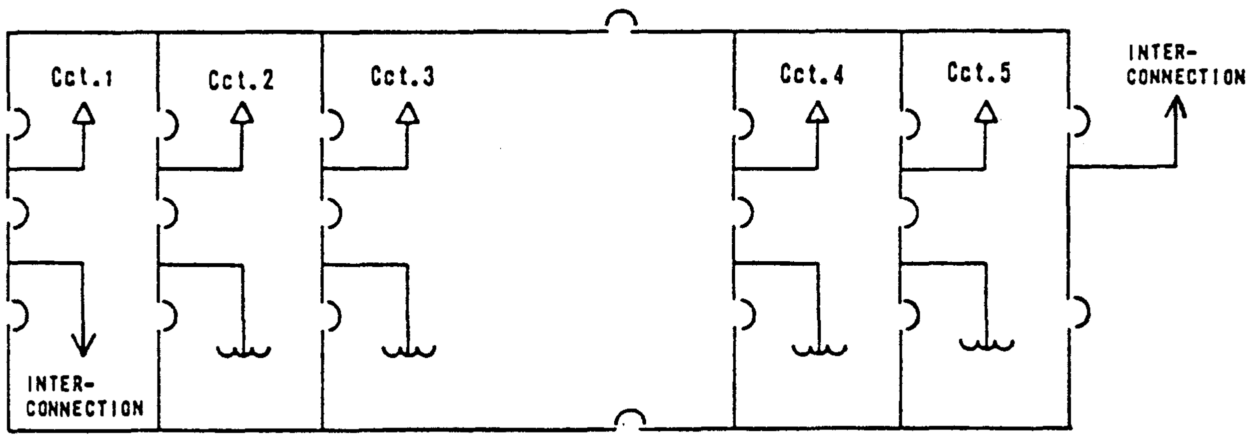


FIGURE 5-15
SINGLE LINE DIAGRAM

500 KV AERIAL/UNDERGROUND SYSTEM
5 LINES

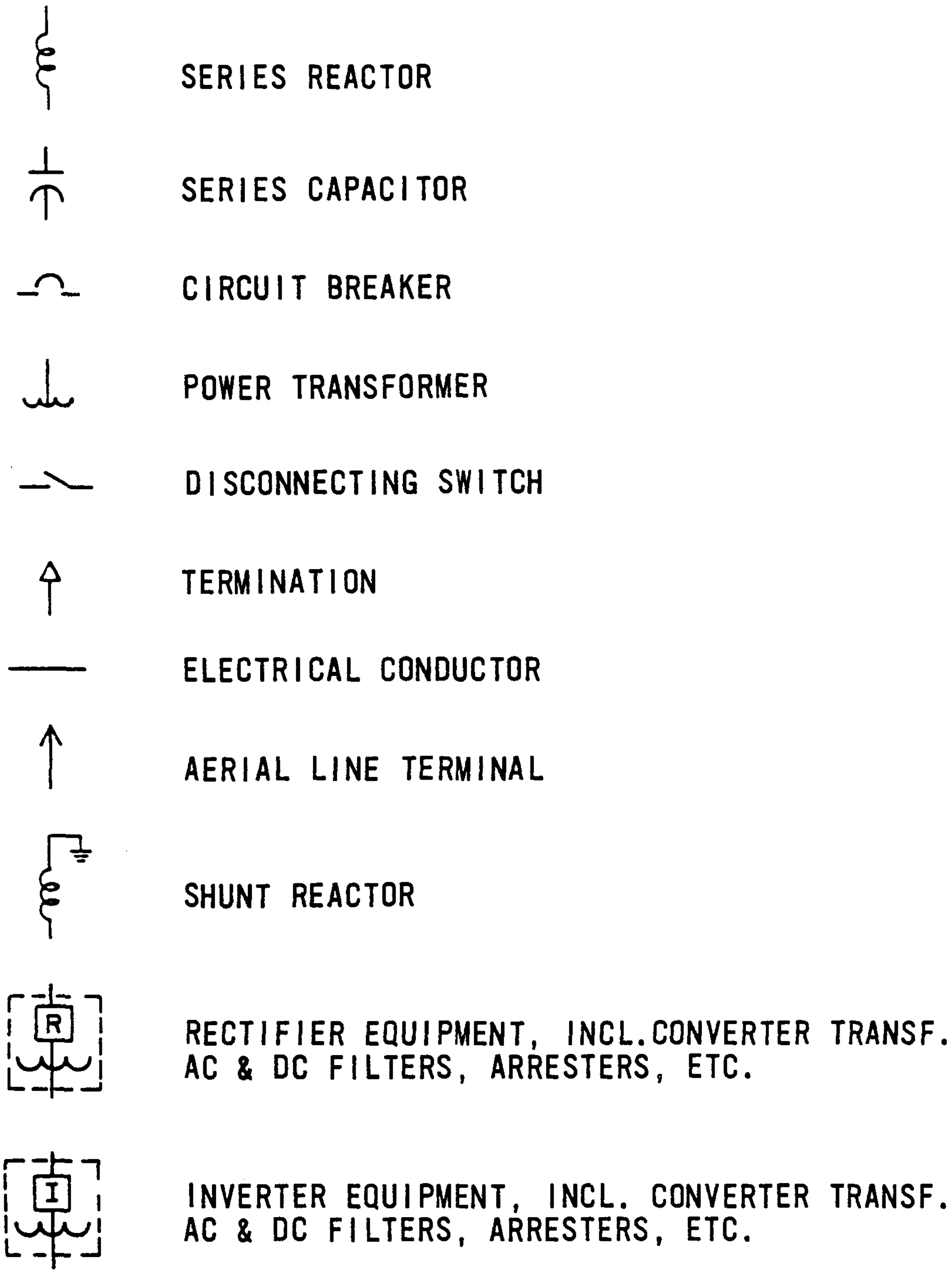


FIGURE 5-16

LEGEND OF SYMBOLS USED ON SINGLE LINE DIAGRAMS

Table 5-1

Substation and Compensation Costs
500 kV HPOPT Cellulose - Insulated Cable
8 Circuits - 16 Lines

Substation	Energy Park Material K$	Energy Park Labor K$	Energy Park Total K$	Mid-Site Material K$	Mid-Site Labor K$	Mid-Site Total K$	Total Radial System K$	Total Network System K$
Real Estate	270	-	270	2,315	-	2,315		
Property Improvements	800	1,205	2,005	690	1,035	1,725		
Bus	2,065	1,160	3,225	1,720	850	2,570		
Circuit Breakers	17,670	1,330	19,000	18,415	1,385	19,800		
Disconnect Switches	3,225	805	4,030	3,195	785	3,980		
Transformers	40,720	2,150	42,870	22,800	1,200	24,000		
Miscellaneous	2,955	1,470	4,425	2,580	1,810	4,390		
Engineering	-	2,220	2,260	-	1,605	1,605		
Maintenance (Capitalized)	93	1,739	1,832	112	2,113	2,225		
Total	67,798	12,079	79,877	51,827	10,843	62,670	142,547	142,547

Shunt Inductive Compensation

	Radial System Material K$	Radial System Labor K$	Radial System Total K$	Network System Material K$	Network System Labor K$	Network System Total K$	Total Radial System K$	Total Network System K$
Energy Park	27,287	4,885	32,172	27,287	4,885	32,172		
Mid-Site	27,442	4,870	32,312	27,442	4,870	32,312		
3 Compensation Stations	175,212	35,580	210,792	175,212	35,580	210,792		
Total	229,941	45,335	275,276	229,941	45,335	275,276	275,276	275,276

Series Inductive Compensation

	Network System Material K$	Network System Labor K$	Network System Total K$	Total Radial System K$	Total Network System K$
Energy Park	16,135	3,045	19,180	-	19,180
System Total				417,823	437,003

Notes: 1. The costs of communication equipment which is external to the terminal substations (such as supervisory master control, microwave relay stations, etc.) are apportioned equally between Energy Park and Mid-Site.

2. All series compensation is assumed at the Energy Park terminal.

Table 5-2

Substation and Compensation Costs
500 kV HPOPT PPP - Insulated Cable
6 Circuits - 12 Lines

Substation	Energy Park Material K$	Energy Park Labor K$	Energy Park Total K$	Mid-Site Material K$	Mid-Site Labor K$	Mid-Site Total K$	Total Radial System K$	Total Network System K$
Real Estate	240	-	240	1,955	-	1,955		
Property Improvements	725	1,090	1,815	605	910	1,515		
Bus	1,540	865	2,405	1,355	670	2,025		
Circuit Breakers	15,250	1,150	16,400	16,000	1,200	17,200		
Disconnect Switches	2,690	670	3,360	2,690	670	3,360		
Transformers	40,720	2,150	42,870	22,800	1,200	24,000		
Miscellaneous	2,495	1,660	4,155	2,475	1,645	4,120		
Engineering	-	2,215	2,215	-	1,635	1,635		
Maintenance (Capitalized)	136	2,569	2,705	103	1,951	2,054		
Total	63,796	12,369	76,165	47,983	9,881	57,864	134,029	134,029

Shunt Inductive Compensation

	Radial System Material K$	Radial System Labor K$	Radial System Total K$	Network System Material K$	Network System Labor K$	Network System Total K$	Total Radial System K$	Total Network System K$
Energy Park	19,721	3,618	23,339	19,721	3,618	23,339		
Mid-Site	19,842	3,611	23,453	19,842	3,611	23,453		
3 Compensation Stations	127,188	27,057	154,245	127,188	27,057	154,245		
Total	166,751	34,286	201,037	166,751	34,286	201,037	201,037	201,037

Series Inductive Compensation

	Network System Material K$	Network System Labor K$	Network System Total K$	Total Radial System K$	Total Network System K$
Energy Park	13,475	2,525	16,000	-	16,000
System Total				335,066	351,066

Notes: 1. The costs of communication equipment which is external to the terminal substations (such as supervisory master control, microwave relay stations, etc.) are apportioned equally between Energy Park and Mid-Site.

2. All series compensation is assumed at the Energy Park terminal.

Table 5-3

Substation and Compensation Costs
765 kV HPOPT PPP - Insulated Cable
9 Lines

Substation	Energy Park Material K$	Energy Park Labor K$	Energy Park Total K$	Mid-Site Material K$	Mid-Site Labor K$	Mid-Site Total K$	Total Radial System K$	Total Network System K$
Real Estate	460	-	460	4,775	-	4,775		
Property Improvements	1,405	2,115	3,520	1,320	1,980	3,300		
Bus	3,915	2,120	6,035	4,320	2,200	6,520		
Circuit Breakers	23,500	1,800	25,300	26,135	1,965	28,100		
Disconnect Switches	4,030	995	5,025	4,500	1,205	5,705		
Transformers	46,300	5,900	52,200	46,365	4,035	50,400		
Miscellaneous	2,610	1,705	4,315	2,590	1,690	4,280		
Engineering	-	3,165	3,165	-	2,890	2,890		
Maintenance (Capitalized)	185	3,858	4,043	194	3,706	3,900		
Total	82,405	21,658	104,063	90,199	19,671	109,870	213,933	213,933

Shunt Inductive Compensation

	Radial System Material K$	Radial System Labor K$	Radial System Total K$	Network System Material K$	Network System Labor K$	Network System Total K$	Total Radial System K$	Total Network System K$
Energy Park	26,280	4,518	30,798	26,280	4,518	30,798		
Mid-Site	27,277	4,620	31,897	27,277	4,620	31,897		
3 Compensation Stations	167,373	33,165	200,538	167,373	33,165	200,538		
Total	220,930	42,303	263,233	220,930	42,303	263,233	263,233	263,233

Series Inductive Compensation

	Network System Material K$	Network System Labor K$	Network System Total K$	Total Radial System K$	Total Network System K$
Energy Park	11,565	2,175	13,740	-	13,740
System Total				477,166	490,906

Notes: 1. The costs of communication equipment which is external to the terminal substations (such as supervisory master control, microwave relay stations, etc.) are apportioned equally between Energy Park and Mid-Site.

2. All series compensation is assumed at the Energy Park terminal.

Table 5-4

Substation and Compensation Costs
500 kV Force-Cooled HPOPT PPP - Insulated Cable
8 Lines

Substation	Energy Park Material K$	Energy Park Labor K$	Energy Park Total K$	Mid-Site Material K$	Mid-Site Labor K$	Mid-Site Total K$	Total Radial System K$	Total Network System K$
Real Estate	285	-	285	2,405	-	2,405		
Property Improvements	845	1,275	2,120	705	1,070	1,775		
Bus	1,940	1,090	3,030	1,590	780	2,370		
Circuit Breakers	17,670	1,330	19,000	18,415	1,385	19,800		
Disconnect Switches	2,785	695	3,480	2,890	725	3,615		
Transformers	40,720	2,150	42,870	22,800	1,200	24,000		
Miscellaneous	2,705	1,920	4,625	2,690	1,900	4,590		
Engineering	-	2,190	2,190	-	1,645	1,645		
Maintenance (Capitalized)	142	2,717	2,859	111	2,106	2,217		
Total	67,092	13,367	80,459	51,606	10,811	62,417	142,876	142,876

Shunt Inductive Compensation

	Radial System Material K$	Radial System Labor K$	Radial System Total K$	Network System Material K$	Network System Labor K$	Network System Total K$	Total Radial System K$	Total Network System K$
Energy Park	13,130	2,405	15,535	13,130	2,405	15,535		
Mid-Site	13,220	2,405	15,625	13,220	2,405	15,625		
3 Compensation Stations	85,515	18,780	104,295	85,515	18,780	104,295		
Total	111,865	23,590	135,455	111,865	23,590	135,455	135,455	135,455

Series Inductive Compensation

	Network System Material K$	Network System Labor K$	Network System Total K$	Total Radial System K$	Total Network System K$
Energy Park	6,720	1,280	8,000	-	8,000
System Total				278,331	286,331

Notes: 1. The costs of communication equipment which is external to the terminal substations (such as supervisory master control, microwave relay stations, etc.) are apportioned equally between Energy Park and Mid-Site.

2. All series compensation is assumed at the Energy Park terminal.

Table 5-5

Substation and Compensation Costs
765 kV Force-Cooled HPOPT PPP - Insulated Cable
6 Lines

Substation	Energy Park Material K$	Energy Park Labor K$	Energy Park Total K$	Mid-Site Material K$	Mid-Site Labor K$	Mid-Site Total K$	Total Radial System K$	Total Network System K$
Real Estate	480	-	480	4,540	-	4,540		
Property Improvements	1,475	2,225	3,700	1,270	1,910	3,180		
Bus	3,605	2,030	5,635	4,265	2,105	6,370		
Circuit Breakers	19,435	1,465	20,900	20,905	1,575	22,480		
Disconnect Switches	3,215	805	4,020	3,530	885	4,415		
Transformers	46,300	5,900	52,200	46,365	4,035	50,400		
Miscellaneous	2,650	1,835	4,485	2,655	1,830	4,485		
Engineering	-	2,975	2,975	-	2,710	2,710		
Maintenance (Capitalized)	177	3,297	3,474	181	3,446	3,627		
Total	77,337	20,532	97,869	83,711	18,496	102,207	200,076	200,076

Shunt Inductive Compensation

	Radial System Material K$	Radial System Labor K$	Radial System Total K$	Network System Material K$	Network System Labor K$	Network System Total K$	Total Radial System K$	Total Network System K$
Energy Park	17,165	2,685	19,850	17,165	2,685	19,850		
Mid-Site	17,261	2,685	19,946	17,261	2,685	19,946		
3 Compensation Stations	109,470	24,930	134,400	109,470	24,930	134,400		
Total	143,896	30,300	174,196	143,896	30,300	174,196	174,196	174,196

Series Inductive Compensation

	Network System Material K$	Network System Labor K$	Network System Total K$	Total Radial System K$	Total Network System K$
Energy Park	6,935	1,320	8,255	—	8,255
System Total				374,272	382,527

Notes: 1. The costs of communication equipment which is external to the terminal substations (such as supervisory master control, microwave relay stations, etc.) are apportioned equally between Energy Park and Mid-Site.

2. All series compensation is assumed at the Energy Park terminal.

Table 5-6

Substation and Compensation Costs
500 kV AC Self-Contained Oil-Filled Cable
8 Lines

Substation	Energy Park Material K$	Energy Park Labor K$	Energy Park Total K$	Mid-Site Material K$	Mid-Site Labor K$	Mid-Site Total K$	Total Radial System K$	Total Network System K$
Real Estate	285	-	285	2,405	-	2,405		
Property Improvements	845	1,275	2,120	705	1,070	1,775		
Bus	1,940	1,090	3,030	1,590	780	2,370		
Circuit Breakers	17,670	1,330	19,000	18,415	1,385	19,800		
Disconnect Switches	2,785	695	3,480	2,890	725	3,615		
Transformers	40,720	2,150	42,870	22,800	1,200	24,000		
Miscellaneous	2,705	1,920	4,625	2,690	1,900	4,590		
Engineering	-	2,190	2,190	-	1,645	1,645		
Maintenance (Capitalized)	142	2,717	2,859	111	2,106	2,217		
Total	67,092	13,367	80,459	51,606	10,811	62,417	142,876	142,876

Shunt Inductive Compensation

	Radial System Material K$	Radial System Labor K$	Radial System Total K$	Network System Material K$	Network System Labor K$	Network System Total K$	Total Radial System K$	Total Network System K$
Energy Park	18,720	3,240	21,960	18,720	3,240	21,960		
Mid-Site	18,800	3,240	22,040	18,800	3,240	22,040		
2 Compensation Stations	79,460	15,780	95,240	79,460	15,780	95,240		
Total	116,980	22,260	139,240	116,980	22,260	139,240	139,240	139,240

Series Inductive Compensation

	Network System Material K$	Network System Labor K$	Network System Total K$	Total Radial System K$	Total Network System K$
Energy Park	9,690	1,810	11,500	-	11,500
System Total				282,116	293,616

Notes: 1. The costs of communication equipment which is external to the terminal substations (such as supervisory master control, microwave relay stations, etc.) are apportioned equally between Energy Park and Mid-Site.

2. All series compensation is assumed at the Energy Park terminal.

Table 5-7

Substation Costs
600 kV DC Self-Contained Oil-Filled Cable
4 Lines

Substation	Energy Park Material K$	Energy Park Labor K$	Energy Park Total K$	Mid-Site Material K$	Mid-Site Labor K$	Mid-Site Total K$
Real Estate	315	-	315	3,240	-	3,240
Property Improvements	990	1,490	2,480	850	1,275	2,125
Bus	1,460	785	2,245	1,035	555	1,590
Circuit Breakers	6,790	510	7,300	10,600	800	11,400
Disconnect Switches	2,640	660	3,300	2,180	545	2,725
Conversion Equipment	214,725	41,575	256,300	230,145	44,155	274,300
Transformers	23,845	1,255	25,100	15,770	830	16,600
Miscellaneous	2,205	1,665	3,870	2,195	1,660	3,855
Engineering	-	11,630	11,630	-	11,815	11,815
Maintenance (Capitalized)	1,725	9,785	11,510	1,750	9,950	11,700
Total	254,695	69,355	324,050	267,765	71,585	339,350

System Total 663,400

Note: The costs of communication equipment which is external to the terminal substations (such as supervisory master control, microwave relay stations, etc.) are apportioned equally between Energy Park and Mid-Site.

Table 5-8

Substation and Compensation Costs
500 kV Single-Phase SF_6, GITL, Rigid System
3 Lines

	Energy Park			Mid-Site			Total	
Substation	Material K$	Labor K$	Total K$	Material K$	Labor K$	Total K$	Radial System K$	Network System K$
Real Estate	160	-	160	1,440	-	1,440		
Property Improvements	550	825	1,375	440	660	1,100		
Bus	1,470	830	2,300	1,520	750	2,270		
Circuit Breakers	22,785	1,715	24,500	25,935	1,955	27,890		
Disconnect Switches	3,350	840	4,190	4,065	1,015	5,080		
Transformers	38,585	4,285	42,870	22,800	1,200	24,000		
Miscellaneous	2,090	1,500	3,590	2,030	1,440	3,470		
Engineering	-	2,125	2,125	-	1,590	1,590		
Maintenance (Capitalized)	149	2,837	2,986	123	2,337	2,460		
Total	69,139	14,957	84,096	58,353	10,947	69,300	153,396	153,396

Shunt Inductive Compensation

	Radial System			Network System			Total	
	Material K$	Labor K$	Total K$	Material K$	Labor K$	Total K$	Radial System K$	Network System K$
Energy Park	4,936	994	5,930	3,936	957	4,893		
Mid-Site	5,096	1,037	6,133	4,096	1,000	5,096		
Total	10,032	2,031	12,063	8,032	1,957	9,989	12,063	9,989

Series Inductive Compensation

	Network System			Total	
	Material K$	Labor K$	Total K$	Radial System K$	Network System K$
Energy Park	4,085	760	4,845	-	4,845
System Total				165,459	168,770

Notes: 1. The costs of communication equipment which is external to the terminal substations (such as supervisory master control, microwave relay stations, etc.) are apportioned equally between Energy Park and Mid-Site.

2. All series compensation is assumed at the Energy Park terminal.

Table 5-9

Substation and Compensation Costs
500 kV Single-Phase SF_6, GITL, Flexible System
5 Lines

Substation	Energy Park Material K$	Energy Park Labor K$	Energy Park Total K$	Mid-Site Material K$	Mid-Site Labor K$	Mid-Site Total K$	Total Radial System K$	Total Network System K$
Real Estate	160	-	160	1,500	-	1,500		
Property Improvements	550	830	1,380	455	680	1,135		
Bus	1,395	785	2,180	1,180	580	1,760		
Circuit Breakers	13,580	1,020	14,600	15,190	1,145	16,335		
Disconnect Switches	2,600	650	3,250	2,235	560	2,795		
Transformers	40,720	2,150	42,870	22,800	1,200	24,000		
Miscellaneous	2,210	1,590	3,800	2,210	1,480	3,690		
Engineering	-	2,025	2,025	-	1,495	1,495		
Maintenance (Capitalized)	129	2,457	2,586	97	1,843	1,940		
Total	61,344	11,507	72,851	45,667	8,983	54,650	127,501	127,501

Series Inductive Compensation

	Network System Material K$	Network System Labor K$	Network System Total K$	Total Radial System K$	Total Network System K$
Energy Park	6,645	1,240	7,885	-	7,885
System Total				127,501	135,386

Notes: 1. The costs of communication equipment which is external to the terminal substations (such as supervisory master control, microwave relay stations, etc.) are apportioned equally between Energy Park and Mid-Site.

2. All series compensation is assumed at the Energy Park terminal.

Table 5-10

Substation and Compensation Costs
500 kV Three-Phase SF_6, GITL, Rigid System
5 Lines

Substation	Energy Park Material K$	Energy Park Labor K$	Energy Park Total K$	Mid-Site Material K$	Mid-Site Labor K$	Mid-Site Total K$	Total Radial System K$	Total Network System K$
Real Estate	160	-	160	1,500	-	1,500		
Property Improvements	550	830	1,380	455	680	1,135		
Bus	1,395	785	2,180	1,180	580	1,760		
Circuit Breakers	13,580	1,020	14,600	15,190	1,145	16,335		
Disconnect Switches	2,600	650	3,250	2,235	560	2,795		
Transformers	40,720	21,50	42,870	22,800	1,200	24,000		
Miscellaneous	2,210	1,590	3,800	2,210	1,480	3,690		
Engineering	-	2,025	2,025	-	1,495	1,495		
Maintenance (Capitalized)	129	2,457	2,586	97	1,843	1,940		
Total	61,344	11,507	72,851	45,667	8,983	54,650	127,501	127,501

Series Inductive Compensation

	Network System Material K$	Network System Labor K$	Network System Total K$	Total Radial System K$	Total Network System K$
Energy Park	6,600	1,230	7,830	-	7,830
System Total				127,501	135,331

Notes: 1. The costs of communication equipment which is external to the terminal substations (such as supervisory master control, microwave relay stations, etc.) are apportioned equally between Energy Park and Mid-Site.

2. All series compensation is assumed at the Energy Park terminal.

Table 5-11

Substation and Compensation Costs
500 kV Resistive Cryogenic Cable
4 Lines

Substation	Energy Park Material K$	Energy Park Labor K$	Energy Park Total K$	Mid-Site Material K$	Mid-Site Labor K$	Mid-Site Total K$	Total Radial System K$	Total Network System K$
Real Estate	160	-	160	1,500	-	1,500		
Property Improvements	550	825	1,375	440	660	1,100		
Bus	1,375	775	2,150	1,235	695	1,930		
Circuit Breakers	17,905	1,350	19,255	21,345	1,605	22,950		
Disconnect Switches	2,480	620	3,100	3,155	790	3,945		
Transformers	42,340	2,230	44,570	22,800	1,200	24,000		
Miscellaneous	2,155	1,550	3,705	2,095	1,490	3,585		
Engineering	-	2,030	2,030	-	1,420	1,420		
Maintenance (Capitalized)	140	2,670	2,810	111	2,114	2,225		
Total	67,105	12,050	79,155	52,681	9,974	62,655	141,810	141,810

Shunt Inductive Compensation

	Radial System Material K$	Radial System Labor K$	Radial System Total K$	Network System Material K$	Network System Labor K$	Network System Total K$	Total Radial System K$	Total Network System K$
Energy Park	17,755	2,960	20,715	17,755	2,960	20,715		
Mid-Site	17,795	2,960	20,755	17,795	2,960	20,755		
Total	35,550	5,920	41,470	35,550	5,920	41,470	41,470	41,470

Series Capacitive Compensation

	Network System Material K$	Network System Labor K$	Network System Total K$	Total Radial System K$	Total Network System K$
Energy Park	10,680	4,915	15,595	-	15,595
System Total				183,280	198,875

Notes: 1. The costs of communication equipment which is external to the terminal substations (such as supervisory master control, microwave relay stations, etc.) are apportioned equally between Energy Park and Mid-Site.

2. All series compensation is assumed at the Energy Park terminal.

Table 5-12

Substation and Compensation Costs
230 kV Superconducting Cable
3 Lines

Substation	Energy Park Material K$	Energy Park Labor K$	Energy Park Total K$	Mid-Site Material K$	Mid-Site Labor K$	Mid-Site Total K$	Total Radial System K$	Total Network System K$
Real Estate	165	-	165	1,320	-	1,320		
Property Improvements	580	865	1,445	410	610	1,020		
Bus	1,365	770	2,135	1,135	610	1,745		
Circuit Breakers	13,595	1,025	14,620	14,265	1,075	15,340		
Disconnect Switches	5,710	1,430	7,140	5,400	1,350	6,750		
Transformers	23,845	1,255	25,100	15,770	830	16,600		
Miscellaneous	2,045	1,505	3,550	2,110	1,565	3,675		
Engineering	-	1,730	1,730	-	1,405	1,405		
Maintenance (Capitalized)	103	1,954	2,057	88	1,674	1,762		
Total	47,408	10,534	57,942	40,498	9,119	49,617	107,559	107,559

Series Capacitive Compensation

	Radial System Material K$	Radial System Labor K$	Radial System Total K$	Total Radial System K$	Total Network System K$
Energy Park	11,660	5,440	17,100	17,100	-
System Total				124,659	107,559

Notes: 1. The costs of communication equipment which is external to the terminal substations (such as supervisory master control, microwave relay stations, etc.) are apportioned equally between Energy Park and Mid-Site.

2. All series compensation is assumed at the Energy Park terminal.

Table 5-13

Substation and Compensation Costs
230 kV Superconducting Cable, Rigid System
3 Lines

Substation	Energy Park Material K$	Energy Park Labor K$	Energy Park Total K$	Mid-Site Material K$	Mid-Site Labor K$	Mid-Site Total K$	Total Radial System K$	Total Network System K$
Real Estate	165	-	165	1,320	-	1,320		
Property Improvements	580	865	1,445	410	610	1,020		
Bus	1,365	770	2,135	1,135	610	1,745		
Circuit Breakers	13,595	1,025	14,620	14,265	1,075	15,340		
Disconnect Switches	5,710	1,430	7,140	5,400	1,350	6,750		
Transformers	23,845	1,255	25,100	15,770	830	16,600		
Miscellaneous	2,045	1,505	3,550	2,110	1,565	3,675		
Engineering	-	1,730	1,730	-	1,405	1,405		
Maintenance (Capitalized)	103	1,954	2,057	88	1,674	1,762		
Total	47,408	10,534	57,942	40,498	9,119	49,617	107,559	107,559

Series Capacitive Compensation

	Radial System Material K$	Radial System Labor K$	Radial System Total K$	Network System Material K$	Network System Labor K$	Network System Total K$	Total Radial System K$	Total Network System K$
Energy Park	346,940	141,605	488,545	339,110	138,405	477,515	488,545	477,515
System Total							596,104	585,074

Notes: 1. The costs of communication equipment which is external to the terminal substations (such as supervisory master control, microwave relay stations, etc.) are apportioned equally between Energy Park and Mid-Site.

2. All series compensation is assumed at the Energy Park terminal.

Table 5-14

Substation Costs
300 kV DC Superconducting Cable
3 Lines

Substation	Energy Park Material K$	Energy Park Labor K$	Energy Park Total K$	Mid-Site Material K$	Mid-Site Labor K$	Mid-Site Total K$
Real Estate	335	-	335	5,340	-	5,340
Property Improvements	1,035	1,550	2,585	1,335	2,005	3,340
Bus	875	690	1,565	2,640	1,860	4,500
Circuit Breakers	58,900	1,200	60,100	69,925	1,875	71,800
Disconnect Switches	4,760	840	5,600	7,875	1,600	9,475
Conversion Equipment	180,270	36,330	216,600	225,540	43,710	269,250
Transformers	-	-	-	15,770	830	16,600
Miscellaneous	2,695	1,670	4,365	4,045	2,670	6,715
Engineering	-	10,350	10,350	-	13,980	13,980
Maintenance (Capitalized)	1,820	10,450	12,270	1,920	12,380	14,300
Total	250,690	63,080	313,770	334,390	80,910	415,300

System Total 729,070

Note: The costs of communication equipment which is external to the terminal substations (such as supervisory master control, microwave relay stations, etc.) are apportioned equally between Energy Park and Mid-Site.

Table 5-15

Substation and Compensation Costs
500 kV Aerial/Underground System
5 Lines

Substation	Energy Park Material K$	Energy Park Labor K$	Energy Park Total K$	Mid-Site Material K$	Mid-Site Labor K$	Mid-Site Total K$	Total Radial System K$	Total Network System K$
Real Estate	160	-	160	1,500	-	1,500		
Property Improvements	550	830	1,380	455	680	1,135		
Bus	1,395	785	2,180	1,180	580	1,760		
Circuit Breakers	13,580	1,020	14,600	15,190	1,145	16,335		
Disconnect Switches	2,600	650	3,250	2,235	560	2,795		
Transformers	40,720	2,150	42,870	22,800	1,200	24,000		
Miscellaneous	2,210	1,590	3,800	2,210	1,480	3,690		
Engineering	-	2,025	2,025	-	1,495	1,495		
Maintenance (Capitalized)	129	2,457	2,586	97	1,843	1,940		
Total	61,344	11,507	72,851	45,667	8,983	54,650	127,501	127,501

Series Capacitive Compensation

	Radial System Material K$	Radial System Labor K$	Radial System Total K$	Network System Material K$	Network System Labor K$	Network System Total K$	Total Radial System K$	Total Network System K$
Energy Park	11,180	5,110	16,290	26,870	11,670	38,540	16,290	38,540
System Total							143,791	166,041

Notes: 1. The costs of communication equipment which is external to the terminal substation. (such as supervisory master control, microwave relay stations, etc.) are apportioned equally between Energy Park and Mid-Site.

2. All series compensation is assumed at the Energy Park terminal.

6. CABLE DESIGN AND AMPACITY

6.1 Introduction

The initial step in determining the design for the naturally-cooled transmission systems evaluated in this study was to calculate the ampacity of several typical cable designs. Usually, several conductor sizes were studied. The charging current for each of the various designs was calculated, and the approximate number of circuits required to meet the ampacity requirements was determined.

Additional refinements to the design were then evaluated, in order to determine the minimum number of circuits which could meet the ampacity required for the normal, first, and second contingency conditions as discussed in Chapter 4. Specific examples of this analysis will be discussed as the individual systems are considered in this chapter.

Once the minimum number of circuits was determined, the ampacity calculations for the specific conductor size and cable design were refined, the charging current was calculated for the final design, and the location of shunt compensation was established. The thermal interference between the naturally-cooled circuits was considered, and 3 m (10 ft.) spacing was chosen to reduce thermal interference to a practical minimum.

In developing the optimum design, other constraints had to be considered, such as circuit breaker ampacities. These considerations were discussed in Chapter 5 under Substation Design.

6. CABLE DESIGN AND AMPACITY

6.1 Introduction (cont'd)

The large number of variables and the complex interactions of the various design parameters required numerous iterations to develop an optimized design. However, knowledge of how changes in the input parameters affected the ampacity, and experience in optimizing the cable system significantly reduced the iterations required to optimize a particular cable design. The complete evaluation process was followed and an optimum design developed whenever different constraints were considered.

Examples of how the design constraints affect the selection of a cable system are as follows. The 500 kV AC self-contained oil-filled cable system cost is less than the 500 kV PPP-insulated pipe-type cable system cost. However, if the costs of the city streets portion of the installation are evaluated, the results indicate that the HPOPT cable is slightly less expensive than the SCOF cable. This is an important result since the majority of cable applications are in urban areas. In addition, the HPOPT design is considered to be more reliable than SCOF cables in city streets. All of the systems studied have the costs broken down so that both private right-of-way and city streets right-of-way are itemized separately.

The ampacity requirement is an important factor affecting the economic relationship between the various systems. In general, the lower ampacity circuits would appear more favorable in an evaluation with a lower ampacity requirement. The cost of the complex pumping and refrigeration equipment required for the high ampacity cryogenic systems makes these systems too costly for a lower ampacity application.

6. CABLE DESIGN AND AMPACITY

6.1 Introduction (cont'd)

Circuit length is another key factor affecting the selection of a cable system. An example would be the selection of a gas-insulated cable for a short cable run in a substation. In this case the gas-insulated cable is the economic choice since the GITL circuits do not require oil handling or pumping equipment.

The point of this discussion is that each particular cable application must be evaluated. Results from this study or any other study cannot be applied without evaluation of the particular application being considered.

6.2 Basic Design Parameters

Basic assumptions for the calculations are listed below. These values are commonly used by Philadelphia Electric Company and may vary in different areas of the country.

Earth Thermal Rho	80°C-cm/Watt
Earth Ambient	23°C
Maximum Earth Interface Temperature	55°C

The 55°C earth interface temperature is a design limitation based on the thermal stability of the soil in the vicinity of the cable. The thermal resistivity of the soil increases as moisture is removed from the soil. Experience has shown that moisture migration does not occur with a 55°C earth interface temperature. However, moisture can be driven from the soil at higher temperatures with a resultant increase in thermal resistance. This can precipitate a thermal runaway condition.

6.2 Basic Design Parameters (cont'd)

Thermal smoothing by slowly circulating the oil in the pipe-type cable was not considered in the study, since backfill correction to a maximum earth thermal rho of 80°C-cm/Watt was included in the installation portion of the study and the ampacity was calculated for this value of earth thermal rho. Thermal smoothing is of no value unless the thermal profile of a line is known. This is not practical in a theoretical study.

The load factor for this particular application was considered to be 100% since the Energy Park would be a base load plant. Since there would be less than 100% availability for the generation units, the losses were calculated assuming 9000 MVA to be available for half of the year and 7200 MVA available during the remainder of the year. The power factor of the load was assumed to be unity for the calculation of ampacity and compensation requirements. All of the cables were assumed to have at least 76 cm (30 in.) of cover.

6.3 High-Pressure Oil-Filled Pipe-Type (HPOPT) Cables

The cellulose-insulated HPOPT cable was considered as the base case for the study, although the ampacity and shunt compensation calculation techniques used for all three of the naturally-cooled HPOPT cables are similar. Therefore, a summary of the method used to determine the 500 kV paper-polypropylene-paper (PPP), laminate-insulated HPOPT cable will be discussed, to illustrate the procedure used to optimize designs for the HPOPT cables.

6. CABLE DESIGN AND AMPACITY

6.3 High-Pressure Oil-Filled Pipe-Type (HPOPT) Cables (cont'd)

Data for 1013 mm^2 (2000 kcmil), 1266 mm^2 (2500 kcmil), and 1520 mm^2 (3000 kcmil) cables were used to calculate the ampacity of each conductor size, using the Neher-McGrath method(1). Using a conductor larger than 1266 mm^2 (2500 kcmil) did not provide a significant increase in ampacity. Therefore, it became evident that a 1266 mm^2 (2500 kcmil) conductor was the largest practical design to consider.

The BIL of the cellulose and PPP-insulated 500 kV HPOPT cable designs was 1800 kV. The other 500 kV cables in the study had BIL's of 1550 kV. Data for the HPOPT cables was received prior to specifying a minimum BIL. Comments have been received that the cost of the HPOPT cables would be reduced if they were redesigned for a 1550 kV BIL. The cost per foot of cable would certainly be reduced. However, in the case of the 500 kV PPP-insulated HPOPT cable the "Grand Total" could be higher. The increased dielectric losses of the thinner-walled cable would probably reduce the ampacity of the cable and any ampacity reduction would require one additional circuit to meet the first contingency ampacity requirements. As stated earlier in the chapter, the iterations between the large number of design parameters are complex and they must be evaluated whenever a design change is being considered.

Shunt inductive reactors were used to compensate the capacitive charging current of the cable(2), and all of the HPOPT circuits were fully compensated. The charging current for each design was calculated and the required number of circuits determined with shunt compensation distributed among three, four, or five stations. By increasing the number of stations to five, it was possible to eliminate one line through the smoothing effect on total current of more distributed compensation.

Once the number of lines and compensation stations was determined, the thermal interference between circuits was calculated and the earth interface temperature was recalculated.

A cross-section of the HPOPT cables is illustrated in Figure 6-1, with details outlined in Table 6-1. Designs for 500 kV paper-insulated, 500 kV paper-polypropylene-paper (PPP) insulated, and 765 kV PPP-insulated HPOPT cables are presented. The 500 kV and 765 kV PPP-insulated HPOPT cables were also used in the force-cooled HPOPT cable evaluation in Section 6.4. The loading and limiting operating temperatures for all of the cable systems included in the study, except the cryogenic systems, are included in Table 6-2.

6.4 Force-Cooled HPOPT PPP-Insulated Cable

The twelve 500 kV PPP-insulated, self-cooled lines can be replaced with eight force-cooled lines by the introduction of chilled circulating oil. In the case of the 765 kV PPP-insulated cable, nine self-cooled lines can be reduced to six force-cooled lines. These reductions in lines are limited by practical considerations of the inlet and outlet temperatures of the oil, and the ability of the system to withstand hydraulic pressure. The most practical oil inlet temperature is dictated by the highest summer earth ambient ($23^{o}C$), since any lower temperature would result in removing heat energy from the earth.

6.4 Force-Cooled HPOPT PPP-Insulated Cable (cont'd)

Assumptions for arriving at the above decisions and techniques for developing the results follow published data by Consolidated Edison Company with respect to their operating 345 kV force-cooled lines.

The cooling oil is permitted to rise to an outlet temperature limit equal to the maximum allowable conductor temperature, minus the temperature drop through the insulation to the oil. Coolant loops were designed to be as long as possible without exceeding a pressure drop of 4.14 MPa (600 psi) over the length of the loop, with maximum pressure limitations of 5.52 MPa (800 psi) on 14.13 cm (5-9/16 in.) pipe, and 4.14 MPa (600 psi) on 27.31 cm (10-3/4 in.) pipe, and 2.76 MPa (400 psi) at the potheads.

In actual operation, the advantages of lower average earth and outdoor air temperatures could result in a lower energy cost for the force-cooled system than shown in Chapter 8, if a four-stage operating cycle is installed: static oil with no oil circulation, oil circulation only, oil circulation with air precoolers, and oil circulation with refrigeration. Evaluation of all these factors for lowered operating cost is beyond the scope of this study. However, assuming an improbable condition of no refrigeration losses, calculations show less than one percent reduction in grand total cost data.

6.4.1 Design Assumptions. The design of the cooling system for 500 kV has been developed from published data for Consolidated Edison 345 kV cables. Inasmuch as the cable size and pipe geometry are almost identical, this

6. CABLE DESIGN AND AMPACITY

6.4 Force-Cooled HPOPT PPP-Insulated Cable

6.4.1 Design Assumptions (cont'd)

data was used to establish maximum lengths of cooling loops for required temperatures and pressure drops.

6.4.2 Cooling Plants.

These are similar to plants supplied to Consolidated Edison, except that the 100% redundancy of equipment required by Consolidated Edison is omitted. However, due to the location of several plants at one site, equivalent reliability can be provided by hydraulically interconnecting the plants with automatic valves and alarms.

6.5 Self-Contained Oil-Filled Cable

6.5.1 500 kV AC Self-Contained Oil-Filled Cable.

The design of the 500 kV ac self-contained, oil-filled (SCOF) PPP-insulated cable was optimized using procedures similar to those used for the HPOPT cables. The design is included in Table 6-3 and the cross-section in Figure 6-2. An additional design parameter available with the SCOF cable is the spacing between conductors. Since the ampacity of the self-contained cables was limited by the earth interface temperature, the thermal interference between conductors could be reduced by increasing the phase-to-phase spacing. It was possible to obtain an ampacity which met the requirements for eight circuits.

6. CABLE DESIGN AND AMPACITY

6.5 Self-Contained Oil-Filled Cable

6.5.1 500 kV AC Self-Contained Oil-Filled Cable (cont'd)

The ampacity of the SCOF cable is higher than the HPOPT ampacity; the spacing between conductors provides additional area for heat dissipation, and a larger conductor is feasible with the SCOF design. However, the larger conductor increases the capacitance and, therefore, the charging current of the SCOF cable.

The cable ampacity was calculated assuming open-circuited sheath operation. A 253 mm^2 (500 kcmil) copper ground conductor was required in this design. Continuous sheath voltages of 126 Volts were calculated[3]. Transient voltage protection was provided with sheath voltage limiters. This is discussed further in the installation section of Chapter 9.

6.5.2 ±600 kV DC Cable. The design of the 600 kV dc self-contained oil-filled cable is also included in Table 6-3, and the cross-section in Figure 6-2. The ampacity of the ±600 kV dc cable was calculated with a nominal 38.1 cm (15 in.) spacing and was found to be almost enough to meet the ampacity requirements for four bipolar circuits. By calculating the maximum thermal interference between circuits, it was determined that a 91.4 cm (36 in.) spacing would permit the required ampacity of 1428 MVA per pole to be attained. The eight-circuit first contingency condition could be used since loss of a cable would take only one pole out of service.

Neither the 55°C earth interface temperature nor the 85°C conductor temperature limited the ampacity. A design value from the cable manufacturer for the maximum temperature drop across the insulation (ΔT) of 32°C actually was the limiting value in determining the ampacity of this cable. The ΔT limit is necessary to guard against excessive electrical stress at the outer diameter of the cable. Stress distribution of a loaded dc cable is reversed as compared to an ac cable, since the stress at the outer diameter of the insulation increases as the temperature drop across the insulation increases. A 2028 mm^2 (4000 kcmil) ground return cable insulated for 15 kV is included in the design.

A pipe-type dc cable was considered, but since both poles would be removed from service whenever a failure occurred, and additional circuits would be required to meet the ampacity requirements, it was determined that a self-contained design was the better alternative.

6. CABLE DESIGN AND AMPACITY (cont'd)

6.6 SF_6 Gas-Insulated Transmission Lines (GITL) Systems

Three SF_6 GITL systems were evaluated; a single-phase rigid system, a single-phase flexible system, and a three-phase rigid system.

6.6.1 Single-Phase, Rigid System. Data for both the rigid and flexible single-phase SF_6 GITL systems were obtained from manufacturers holding EPRI and ERDA contracts to develop GITL systems. Ampacity calculations were conducted using computer programs developed by these EPRI- and ERDA-sponsored programs[4]. Design data for the single-phase SF_6, GITL, rigid system is presented in Table 6-4, and a cross-section is illustrated in Figure 6-3. The design is much larger than what might be considered a typical 500 kV single-phase SF_6, GITL rigid cable design, because of the ampacity requirements.

The enclosure temperature of 69°C and the backfill boundary temperature of 60°C for the rigid system exceed the design value of 55°C for the earth interface temperature. The enclosure temperature could be reduced by increasing the conductor size or by increasing the phase-to-phase spacing between conductors. However, since the design temperature is exceeded only under first contingency conditions and the cost increase to correct it is small, the EPRI/ERDA contractors who submitted the cable design were not requested to redesign the system.

6.6 SF_6 Gas-Insulated Transmission Lines (GITL) Systems

6.6.1 Single-Phase, Rigid System (cont'd)

The charging current for all three of the GITL designs is small enough that shunt compensation is not needed to meet ampacity requirements. The shunt compensation required for the single-phase, rigid, SF_6 GITL is required for power factor correction as discussed in Chapter 4.

The design is for a fully-bonded system. Before advantage can be taken of open-circuited sheath operation, further analysis is required to determine the hazards of the magnetic fields adjacent to circuits with high ampacities and large phase-to-phase spacings.

6.6.2 Single-Phase, Flexible System. The cable cross-section is shown in Figure 6-4 and detailed design data presented in Table 6-5. The physical requirements of a flexible cable system limit the dimensions and particularly the thickness of materials involved in the cable construction. Consequently, the flexible design has an ampacity only half that of the single-phase rigid design. A total of five circuits is required for ampacity or transient stability conditions.

6.6.3 Three-Phase, Rigid System. The three-phase, rigid system cross-section is illustrated in Figure 6-5 and the design values shown in Table 6-6. The design was developed from the EPRI 7816/ERDA E(49-18)-1560 Final Report(5). The ampacity was calculated using techniques in Appendix III of reference (5) and data from reference (6). Five circuits were needed to meet ampacity requirements.

6.7 Resistive Cryogenic Cable

Two resistive cryogenic cables were evaluated. A 500 kV resistive cryogenic cable was fully evaluated, while a 345 kV resistive cryogenic cable, rigid system was given technical evaluation but only minimal economic analysis, due to the embryonic nature of the cable system design.

6.7.1 500 kV Resistive Cryogenic Cable. The cable ampacity and design was developed under an EPRI and ERDA-funded project to develop a 500 kV resistive cryogenic cable. Ampacity requirements were met with a four-circuit 3750 MVA design. The cable cross-section is illustrated in Figure 6-6 and the design details described in Table 6-7. Not shown in the cross-section is a 22 cm (8.75 in.) inside diameter liquid nitrogen return pipe. One return pipe would be required for each of the four circuits, as illustrated in the installation drawing in Chapter 11. The large diameter of the conductor was responsible for the high charging current. Two shunt compensation stations were required to maintain the line loading within cable ampacity. Hydraulic and cryogenic refrigeration details are discussed in Chapter 7.

6. CABLE DESIGN AND AMPACITY

6.7 Resistive Cryogenic Cable (cont'd)

6.7.2 345 kV Resistive Cryogenic Cable, Rigid System. The cable cross-section is shown in Figure 6-7. The ampacity and design were determined completely by the EPRI/ERDA program to develop a liquid nitrogen cooled, vacuum-insulated, resistive cryogenic, rigid system. The 345 kV design is an extrapolation of work at 138 kV. Due to concerns over lack of technical details and a preliminary evaluation indicating a poor economic performance, this system was not studied in the same detail as other systems included in the study. No compensation or system planning analyses were pursued. Chapter 11 contains the general discussion and evaluation of this system.

6.8 Superconducting Cable Systems

Three superconducting cable systems were studied; a 230 kV superconducting cable, a 230 kV superconducting rigid cable system, and a 300 kV dc superconducting cable system. All three of these systems met the ampacity requirements with the minimum number of three circuits. Shunt compensation is not required for any of the superconducting cables.

6.8.1 230 kV Superconducting Cable. The design of the 230 kV superconducting cable is illustrated in Figure 6-8. Design data was obtained for a 5000 MVA ampacity. Consequently, no ampacity calculations or alterations of the design were required.

6.8 Superconducting Cable Systems (cont'd)

6.8.2 230 kV Superconducting Rigid Cable. This superconducting cable system would have met the ampacity requirements with a 138 kV system. However, it was not possible to use the lower voltage system due to ampacity limitations of substation buses and circuit breakers. Analysis of transient stability also demonstrated that the 138 kV system would not be a viable solution as described in Chapter 4. Consequently, a 230 kV system was selected for this application. The 230 kV design has an ampacity significantly higher than the 5000 MVA required for the application being considered in this report, but the size of the cable was determined by the BIL requirement. The 230 kV superconducting rigid cable cross-section is shown in Figure 6-9.

6.8.3 300 kV DC Superconducting Cable. The 300 kV dc superconducting cable system is designed to operate as a 300 kV monopolar system, which requires only three cables to meet ampacity requirements. A bipolar design would require four cables, additional dc circuit breakers, and a second dc substation at each terminal. The cable design uses a superconducting sheath which transmits all of the return current. The design is shown in Figure 6-10. The dc bus arrangement is presented in detail in Chapter 5.

6. CABLE DESIGN AND AMPACITY

REFERENCES

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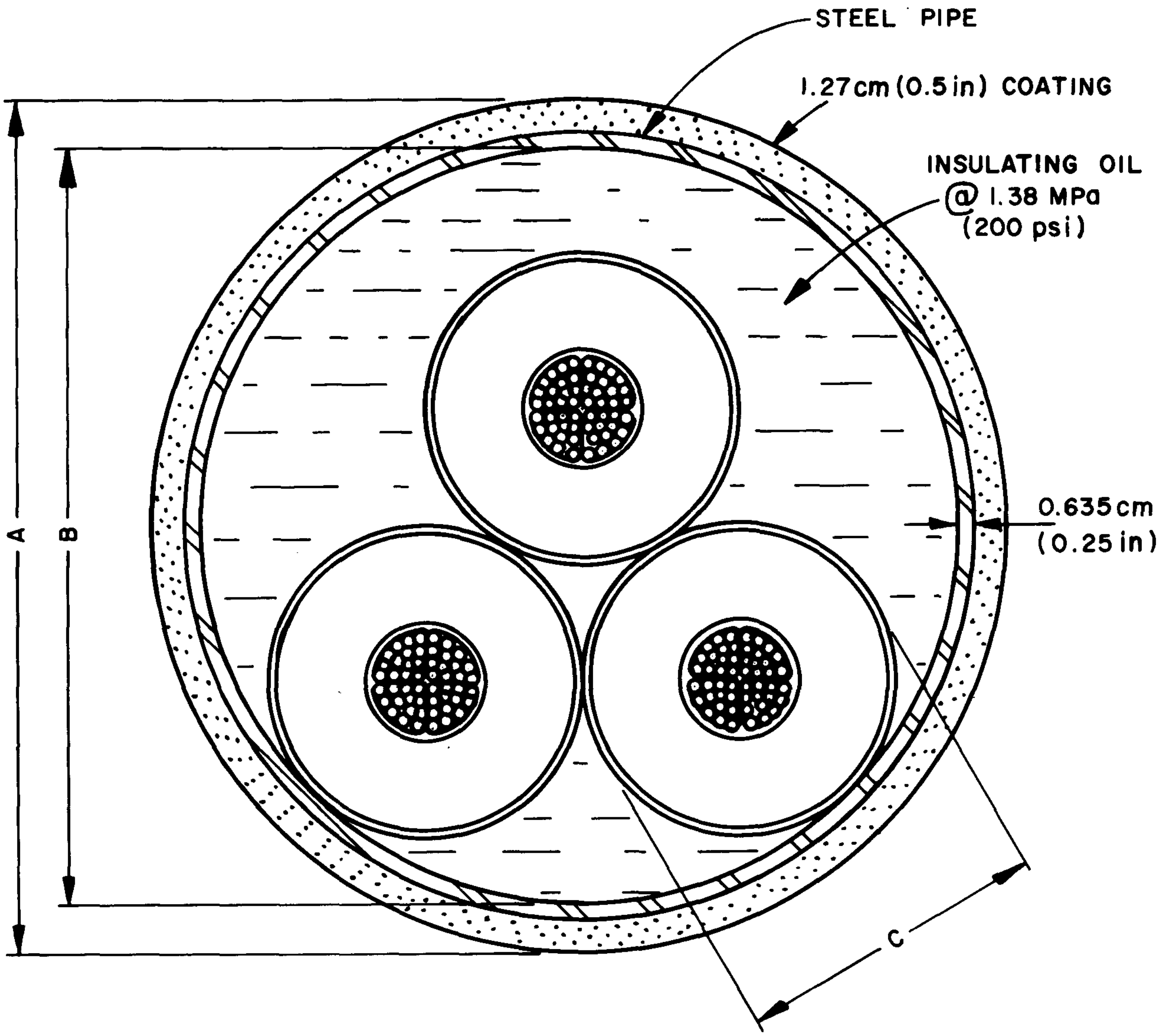
6. W. Deans, "Aluminum in Heavy Current Conductors," AIEE Transactions Vol. 74, pp. 1192-1200, December, 1955.



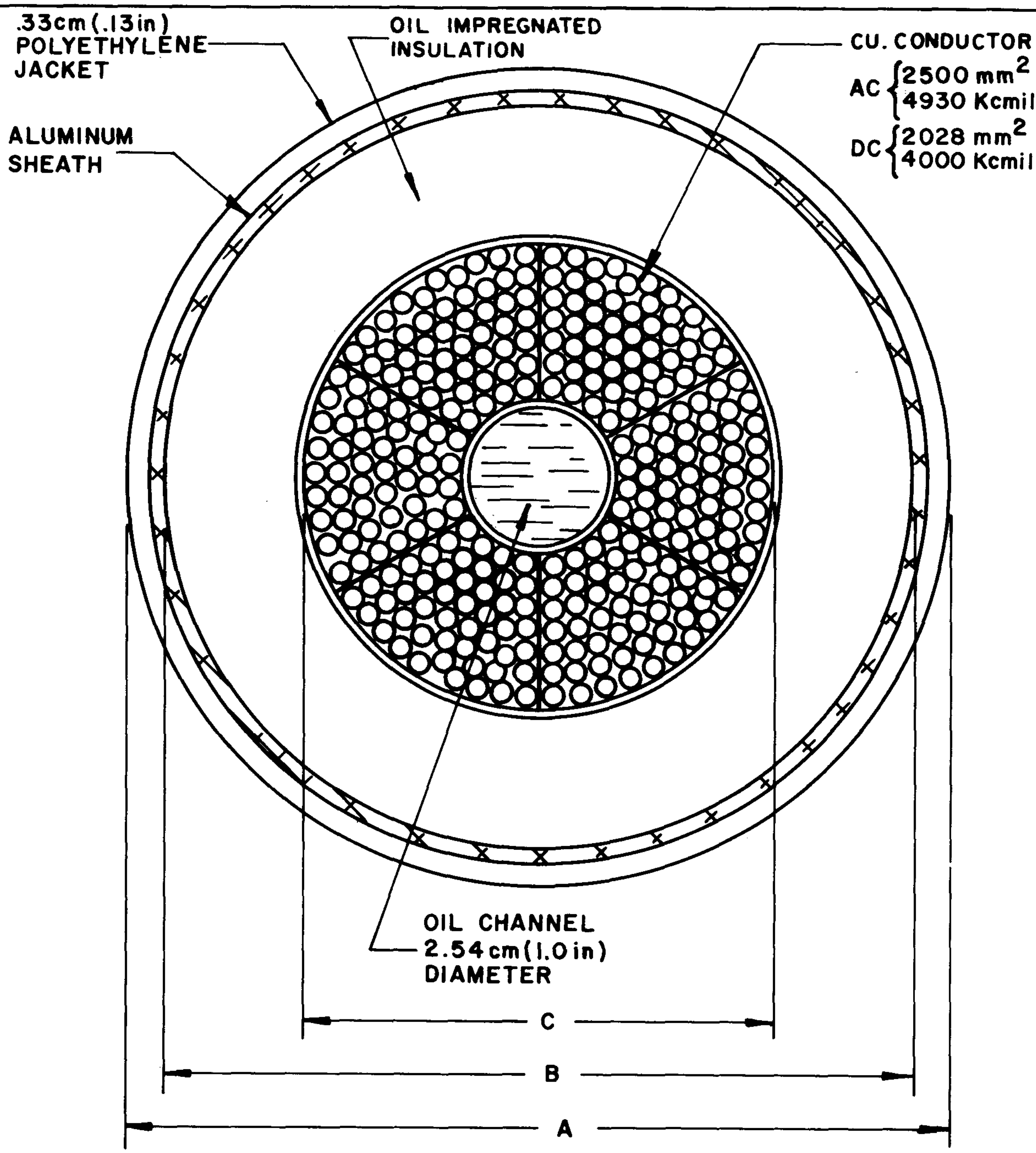
DESIGN	A cm	A in	B cm	B in	C cm	C in
500kV CELLULOSE	34.93	13.75	31.12	12.25	12.01	4.73
500kV PPP	29.85	11.75	26.04	10.25	10.21	4.02
765kV PPP	34.93	13.75	31.12	12.25	12.50	4.92

CONDUCTORS ARE 1267 mm^2 (2500 kcmil) COPPER

INTERNAL CROSS SECTIONAL VIEW

HPOPT CABLE

FIG. 6-1

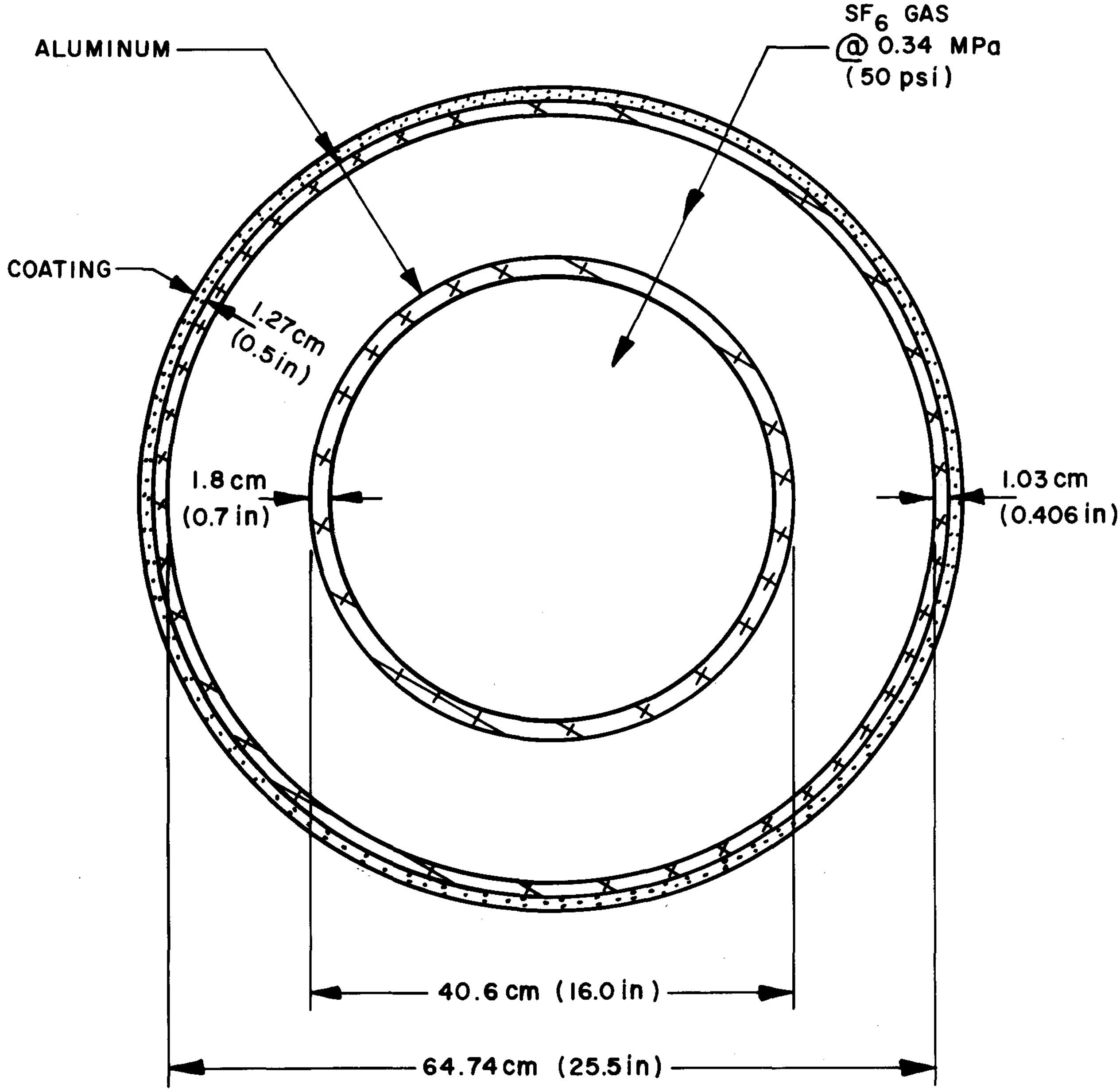


DESIGN	A cm	A in	B cm	B in	C cm	C in
500kV AC PPP	13.4	5.27	12.22	4.8	7.62	3.0
600kV DC CELLULOSE	12.4	4.89	11.5	4.54	6.22	2.45

INTERNAL CROSS SECTIONAL VIEW

SELF-CONTAINED OIL-FILLED CABLE

FIG. 6-2



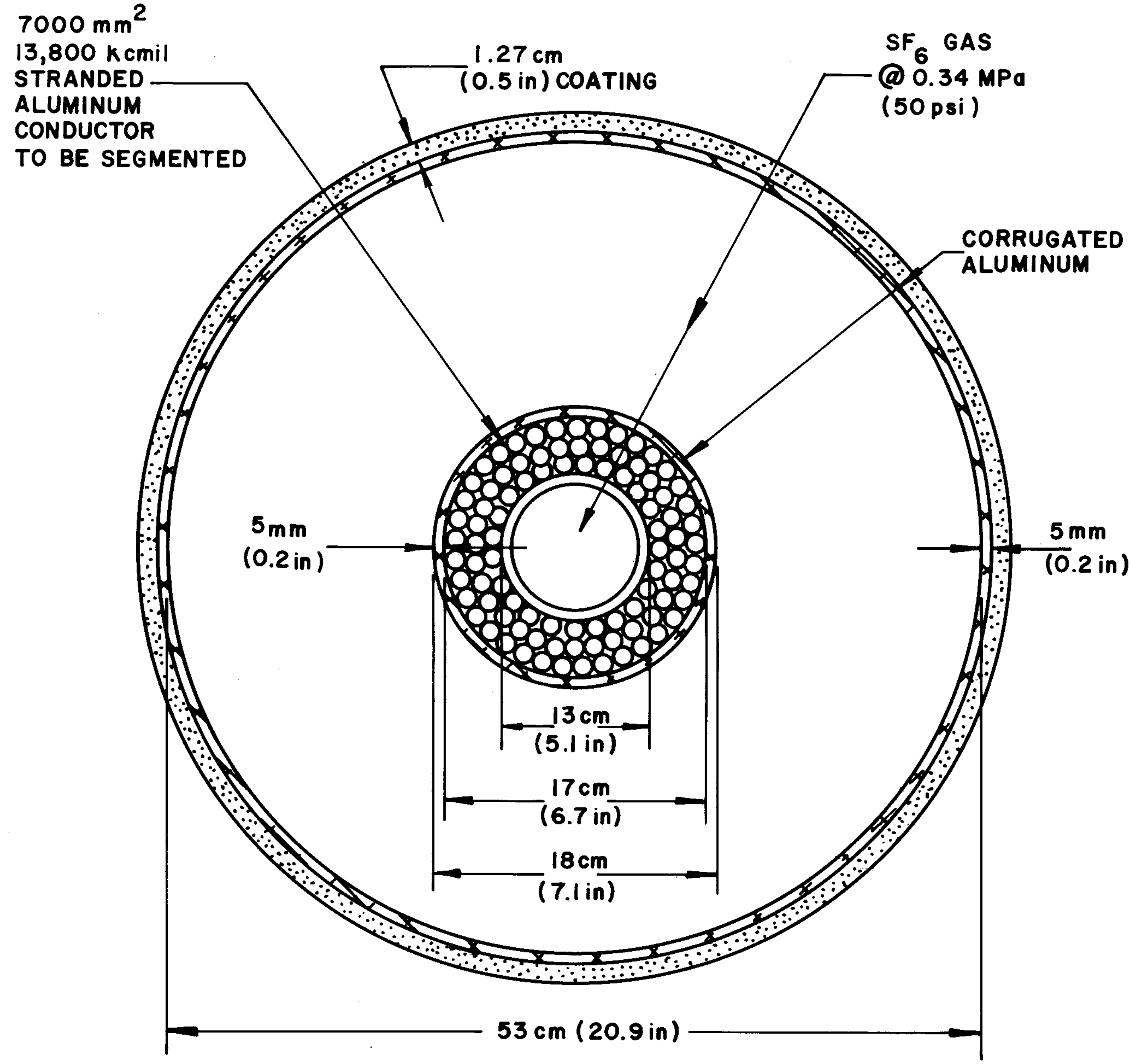
INSULATING SPACERS AND PARTICLE TRAPS ARE NOT SHOWN

INTERNAL CROSS SECTIONAL VIEW

500kV SINGLE-PHASE SF$_6$, GITL,

RIGID SYSTEM

FIG. 6-3



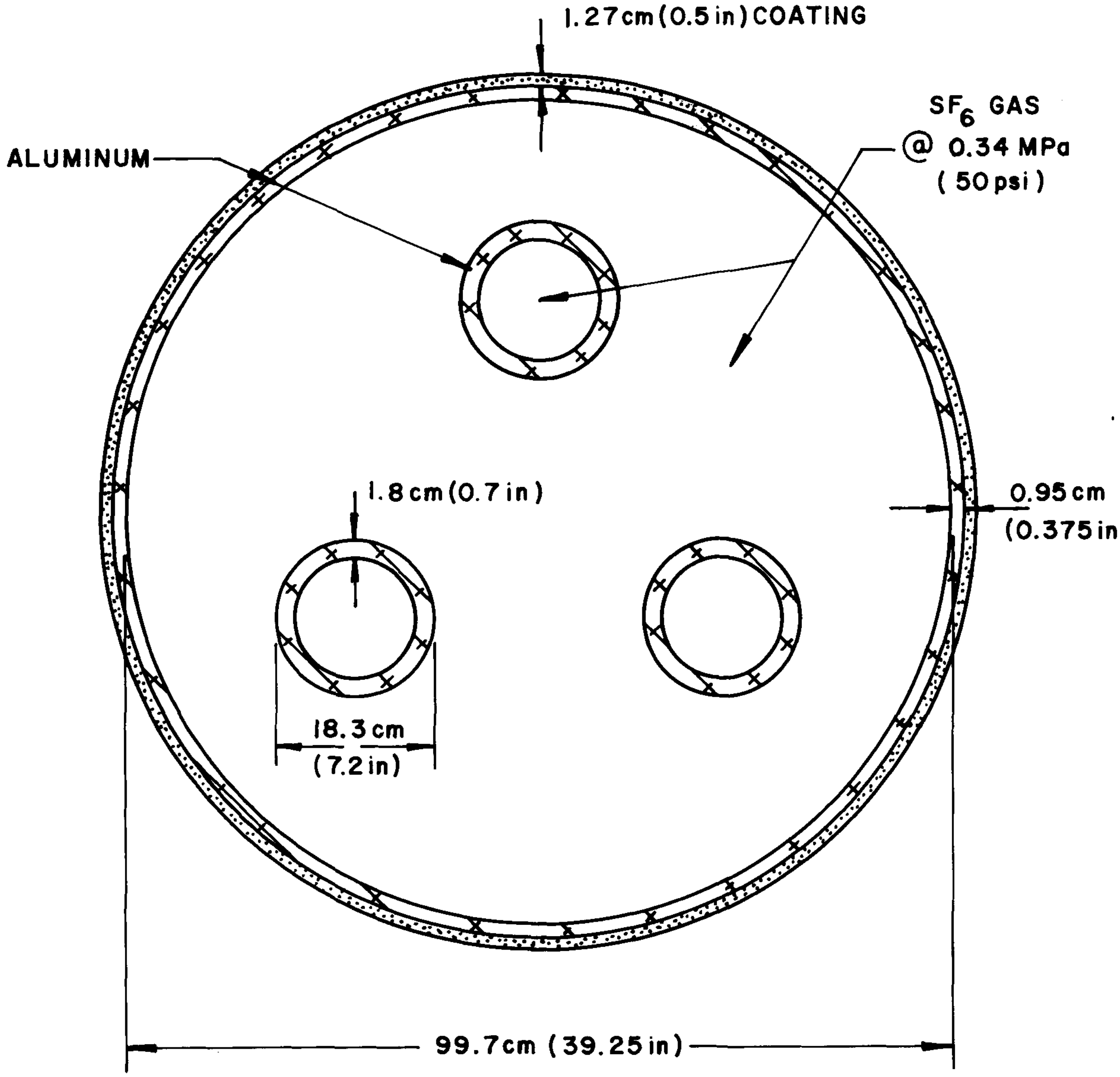
INSULATING SPACERS ARE NOT SHOWN

INTERNAL CROSS SECTIONAL VIEW

500kV SINGLE-PHASE SF_6, GITL,

FLEXIBLE SYSTEM

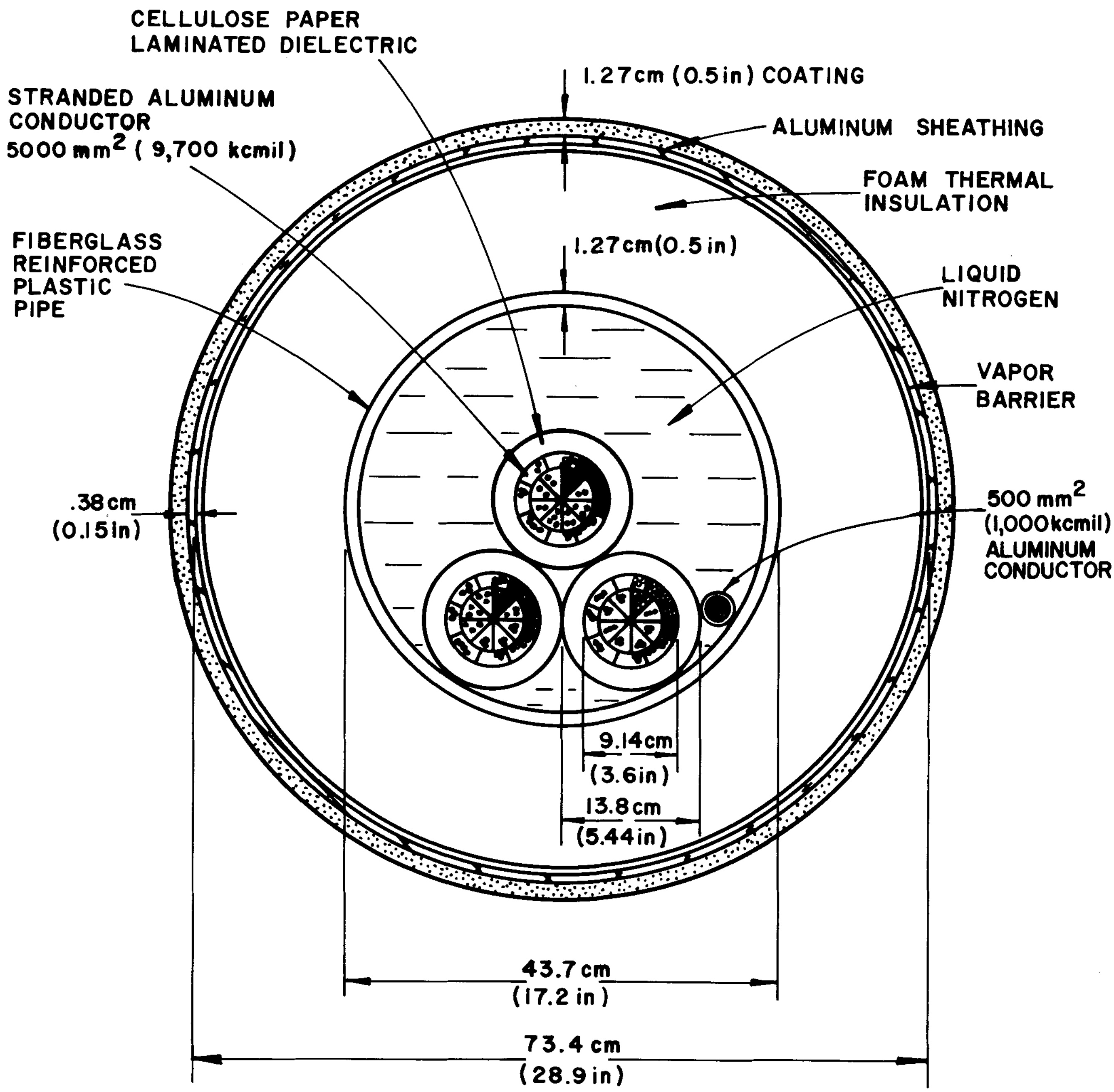
FIG. 6-4



INSULATING SPACERS AND PARTICLE TRAPS ARE NOT SHOWN

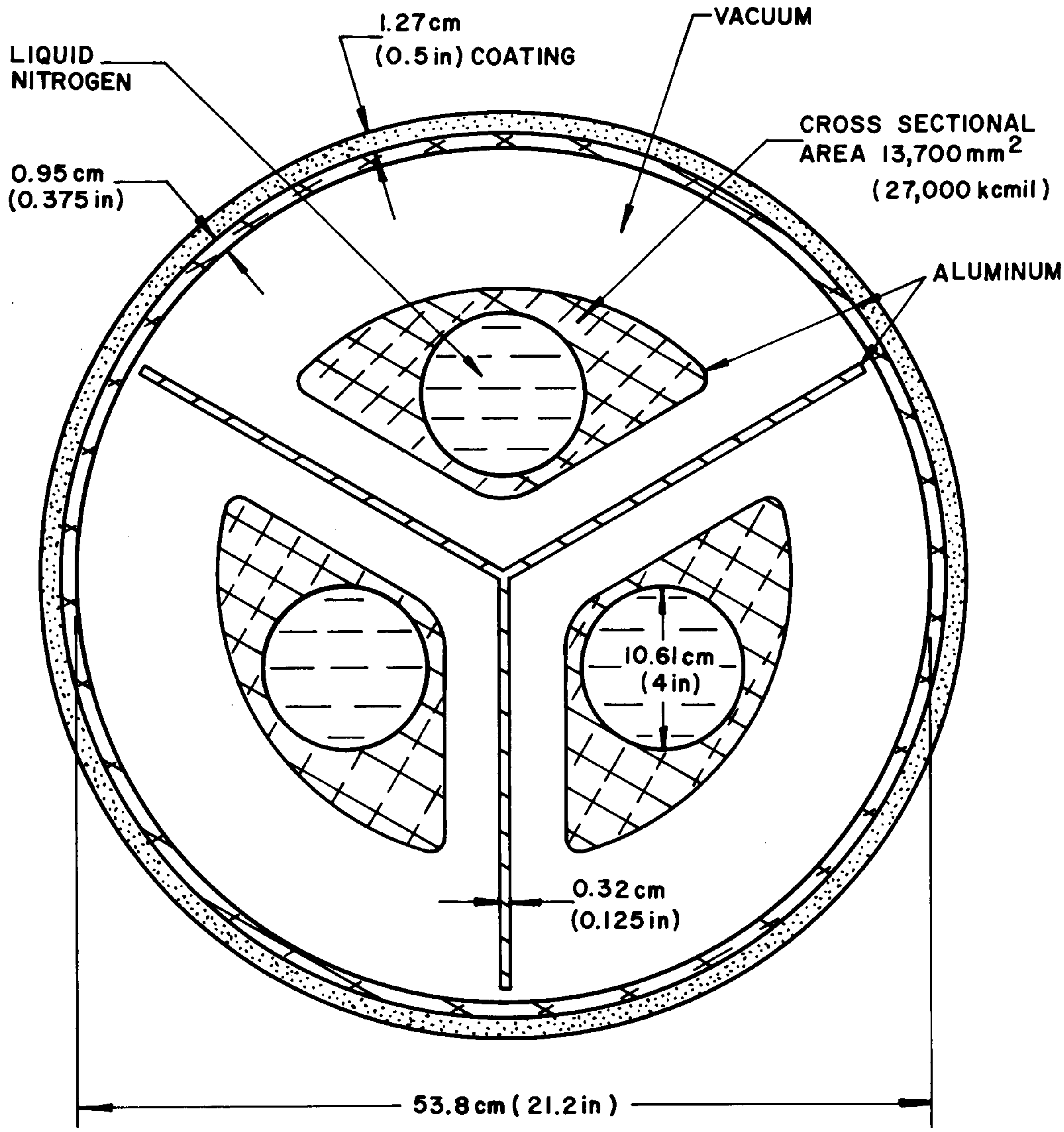
INTERNAL CROSS SECTIONAL VIEW
500kV THREE-PHASE SF$_6$, GITL,
RIGID SYSTEM

FIG. 6-5



NORMAL OPERATING TEMP. RANGE 65° TO 97° K
NORMAL OPERATING PRESSURE RANGE 0.61 TO 0.82 MPa
(88 TO 118 psi)
LIQUID NITROGEN RETURN PIPE IS NOT SHOWN

INTERNAL CROSS SECTIONAL VIEW
500kV RESISTIVE CRYOGENIC CABLE
FIG. 6-6



NORMAL N_2 OPERATING TEMP. RANGE 65° TO 130°K

NORMAL N_2 OPERATING PRESSURE RANGE 3.55 TO 6.07 MPa
(515 TO 880 psi)

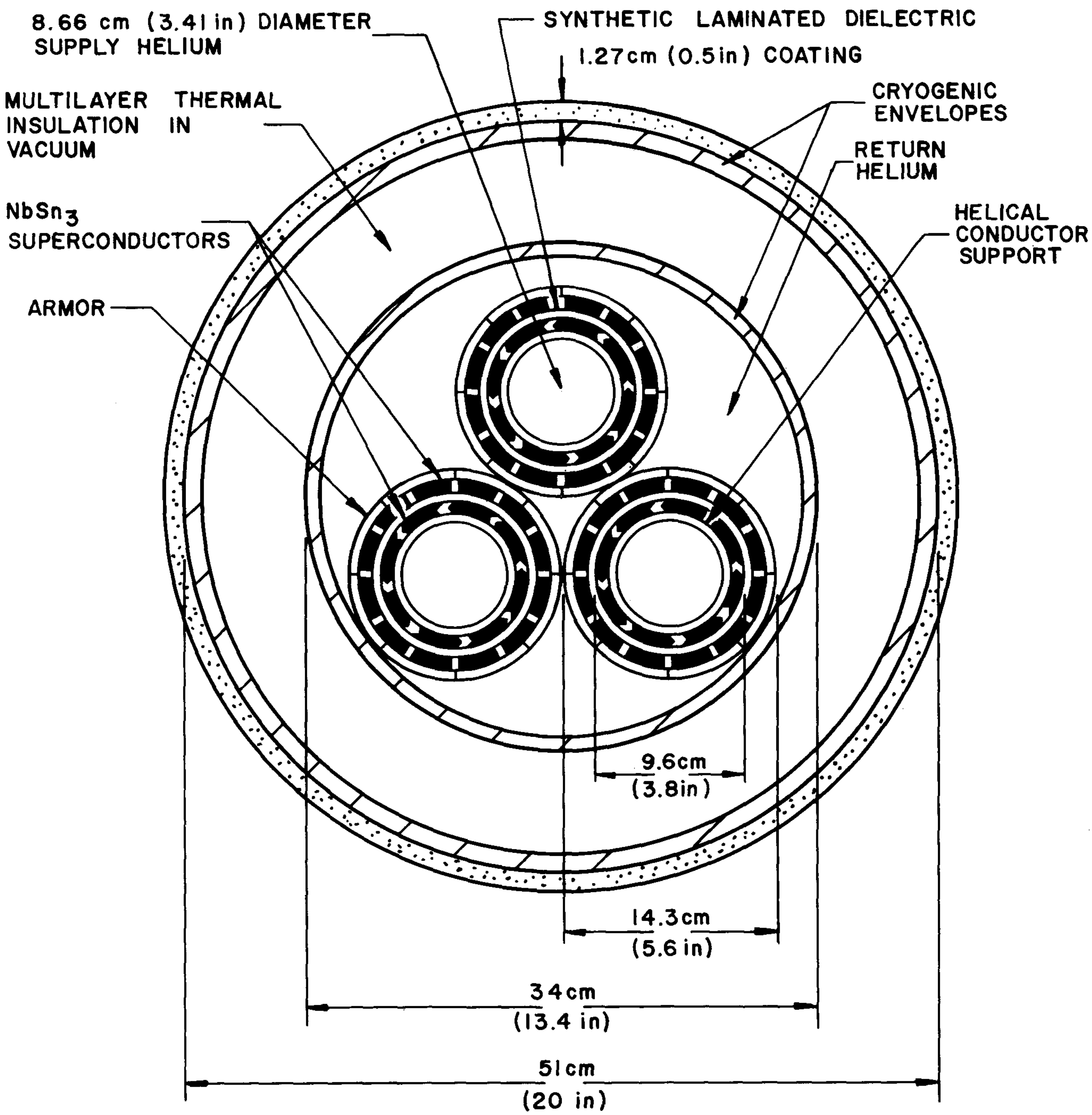
SPACERS ARE NOT SHOWN

INTERNAL CROSS SECTIONAL VIEW

345kV RESISTIVE CRYOGENIC CABLE,

RIGID SYSTEM

FIG. 6-7



NORMAL OPERATING TEMP. RANGE 6.7° TO 8.5° K

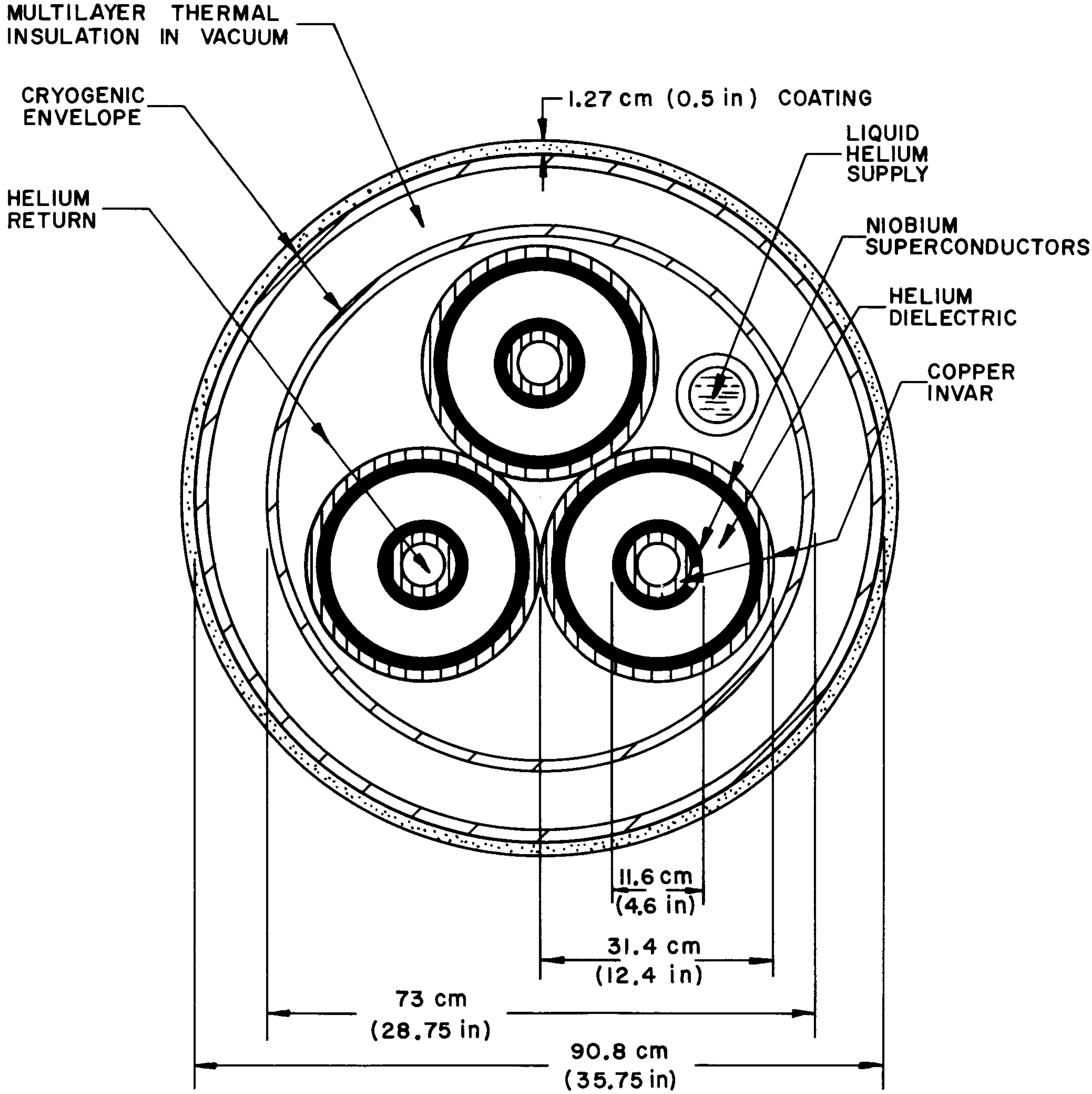
NORMAL HELIUM OPERATING PRESSURE 0.61 TO 1.52 MPa
(88 TO 220 psi)

THERMAL INSULATING SPACERS NOT SHOWN

INTERNAL CROSS SECTIONAL VIEW

230kV AC SUPERCONDUCTING CABLE

FIG. 6-8



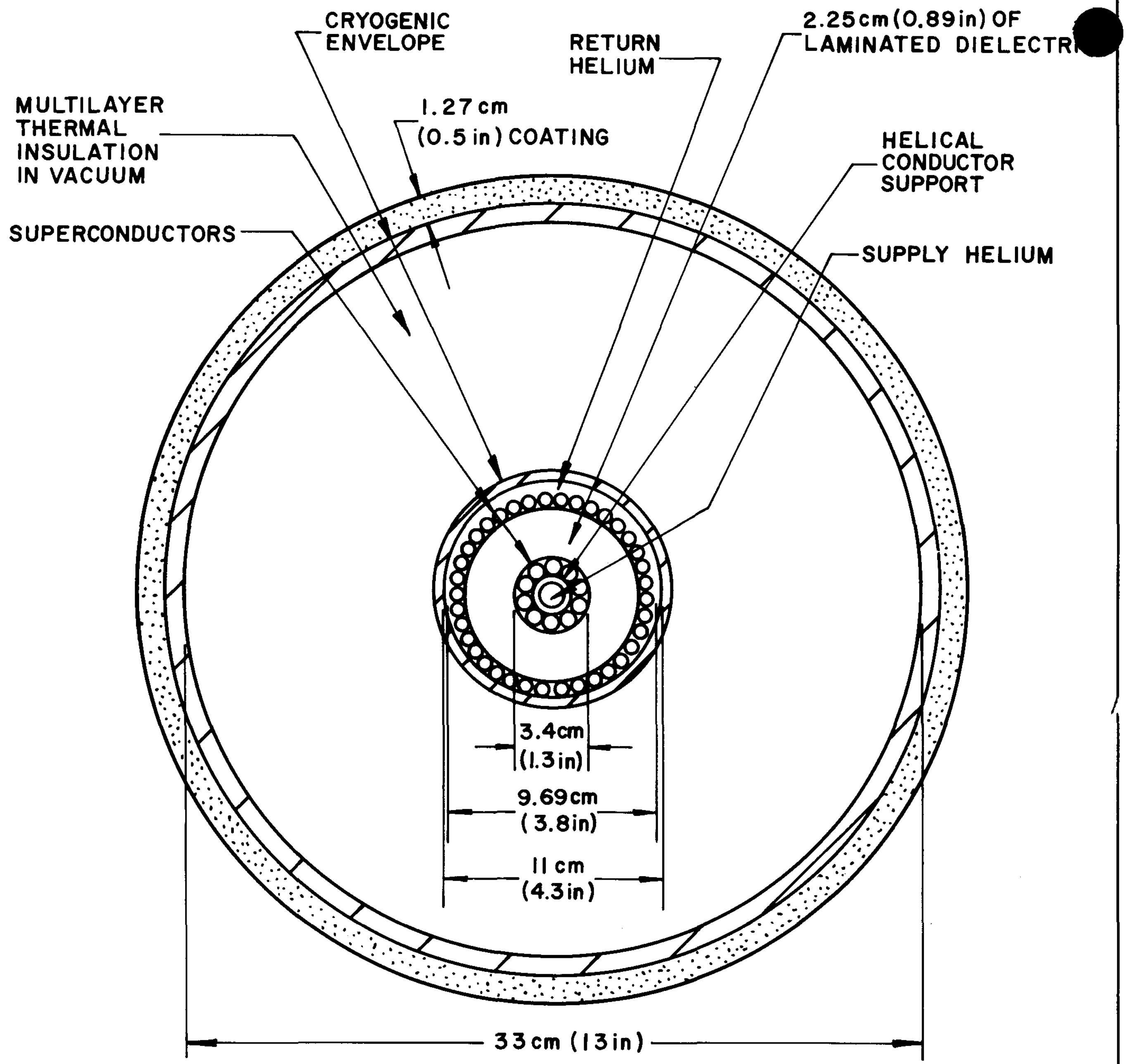
NORMAL OPERATING TEMP. RANGE 4.6° TO 5.1° K

NORMAL HELIUM OPERATING PRESSURE .662 TO .689 MPa (96 TO 100 psi)

SPACERS ARE NOT SHOWN

INTERNAL CROSS SECTIONAL VIEW
230kV SUPERCONDUCTING CABLE, RIGID SYSTEM

FIG. 6-9



NORMAL OPERATING TEMP. RANGE 10° TO 12° K

NORMAL HELIUM OPERATING PRESSURE 0.81 TO 1.62 MPa (117 TO 235 psi)

SPACERS ARE NOT SHOWN

INTERNAL CROSS SECTIONAL VIEW
300kV DC SUPERCONDUCTING CABLE

FIG. 6-10

Table 6-1

HPOPT Cable Design

	500 kV Cellulose	500 kV PPP	765 kV PPP
Conductor			
size		1266 mm^2 (2,500 kcmil)	
material		lead alloy coated copper	
stranding		compact segmental	
diameter (over binding)		4.6 cm (1.824 in.)	
Insulation			
material	Paper	Paper-Polypropylene-Paper (PPP)	PPP
thickness	3.4 cm (1.340 in.)	2.54 cm (1.000 in.)	3.7 cm (1.450 in.)
thermal rho		550°C-cm/Watt	
power factor 90°C	.002	.0005	.0005
SIC	3.5	2.75	2.75
impregnant	Naphthenic Base Mineral Oil	Polybutene Oil	Polybutene Oil
Shield			
type		Tinned Copper	
thickness		.013 cm (0.005 in.)	
width		3.8 cm (1-½ in.)	
overlap		.32 cm (1/8 in.) Open Butt	
number		One	
lay		3.5 cm (1-3/8 in.)	
intercalation		.006 cm (.0025 in.) Metalized Mylar Tape	
Skid Wires			
material		Non-magnetic Stainless Steel	
lay		7.6 cm (3 in.)	
size		.25 x 5 cm (0.100 x 0.200 in.) Half-Round	
number		Two	

Table 6-1 (continued)

	500 kV Cellulose	500 kV PPP	765 kV PPP
Pipe			
type		ERW Steel ASTM A 523	
I.D.	31.1 cm (12.25 in.)	26 cm (10.25 in.)	31.1 cm (12.25 in.)
O.D.	32.4 cm (12.75 in.)	27.3 cm (10.75 in.)	32.4 cm (12.75 in.)
Coating			
type		Somastic	
thickness		1.3 cm (½ in.)	
thermal rho		100	
Installation			
Depth of Burial		76 cm (30 in.)	
Completed Cable Systems			
Cable O.D.	12 cm (4.73 in.)	10.2 cm (4.02 in.)	12.5 cm (4.92 in.)
Weight	24 kg/cond.-m (16.1 lbs./cond.-ft.)	19.5 kg/cond.-m (13.1 lbs./cond.-ft.)	24.6 kg/cond.-m (16.5 lbs./cond.-ft.)
BIL - kV	1800	1800	2100
Number of Lines Req'd to Transmit 10,000 MW	16	12	9
Center-to-Center Spacing		3 m (10 ft.)	

Table 6-2

Line Loading

	MVA/Line Loading	°C Conductor Temperature	°C Enclosure Temperature	°C Backfill Boundary Temperature
500 kV HPOPT Cellulose-Insulated Cable (8 circuits - 16 lines)				
16 lines - normal	680	74	61	51
15 lines - 1st contingency	719	78	63	53 **
14 lines - 2nd contingency *	598	+	+	+
500 kV HPOPT-PPP Insulated Cable (6 circuits - 12 lines)				
12 lines - normal	870	77	58	52
11 lines - 1st contingency	941	86 **	63	56 **
10 lines - 2nd contingency *	789	+	+	+
765 kV HPOPT-PPP Insulated Cable *** (9 circuits - 9 lines)				
9 lines - normal	1216	74	56	50
8 lines - 1st contingency	1350	85 **	63	54
7 lines - 2nd contingency *	1160	+	+	+
500 kV Force Cooled HPOPT-PPP Insulated Cable (8 circuits - 8 lines)				
8 lines - normal	1274	85 **	+	+
7 lines - 1st contingency	1448	85 **	36.4	+
6 lines - 2nd contingency *	1274	85 **	+	+
765 kV Force Cooled HPOPT-PPP Insulated Cable (6 circuits - 6 lines)				
6 lines - normal	1739	85 **	+	+
5 lines - 1st contingency	2087	85 **	33.4	+
4 lines - 2nd contingency *	1957	85 **	+	+

* 7500 MVA rating for 2nd contingency
** Limiting value
*** MVA rating based on 750 kV operation
\+ Temperatures below rated values

Table 6-2 (Continued)

	MVA/Line Loading	°C Conductor Temperature	°C Enclosure Temperature	°C Backfill Boundary Temperature
500 kV AC Self-Contained Oil-Filled Cable (8 circuits - 8 lines)				
8 lines - normal	1340	+	+	+
7 lines - 1st contingency	1507	73	55 **	+
6 lines - 2nd contingency *	1340	+	+	+
600 kV DC Self-Contained Oil-Filled Cable 4 bipolar circuits - 8 poles)				
8 poles - normal	1250	+	+	+
7 poles - 1st contingency	1429	++	52 ++	++
6 poles - 2nd contingency *	1250	+	+	+
500 kV Single-Phase SF_6, GITL, Rigid System (3 circuits - 3 lines)				
3 lines - normal	3333	+	+	+
2 lines - 1st contingency	5000	+	69 +++	60 +++
1 line - 2nd contingency	2500	+	+	+
500 kV Single-Phase SF_6, GITL, Flexible System (5 circuits - 5 lines)				
5 lines - normal	2000	+	+	+
4 lines - 1st contingency	2500	+	55 **	+
3 lines - 2nd contingency *	2500	+	55 **	+
500 kV Three-Phase SF_6, GITL, Rigid System (5 circuits - 5 lines)				
5 lines - normal	2000	+	+	+
4 lines - 1st contingency	2500	+	55 **	+
3 lines - 2nd contingency *	2500	+	55 **	+

* 7500 MVA rating for 2nd contingency
** Limiting value
*** MVA rating based on 750 kV operation
\+ Temperatures below rated values
++ See discussion in Section 6.5.2
+++ See discussion in Section 6.6.1

Table 6-3

Self-Contained Oil-Filled Cable Designs

	500 kV AC		±600 kV DC	
Copper Conductor				
Area	2500 mm^2	(4930 kcmil)	2028 mm^2	(4000 kcmil)
Oil Channel Diameter	2.54 cm	(1 inch)	2.54 cm	(1 inch)
Outside Diameter	7.62 cm	(3 inches)	6.22 cm	(2.45 inches)
Stranding	Milliken		Concentric	
Insulation				
Material	PPP		high density cellulose paper	
Thermal rho	650°C-cm/Watt		550°C-cm/Watt	
Power Factor	.0007		not applicable	
SIC	2.75		not applicable	
Impregnant	polybutene oil		low viscosity mineral oil	
Thickness	2.29 cm	(.9 inch)	2.63 cm	(1.035 inch)
Shield				
Material	composite carbon black paper, metalized carbon black paper, tinned copper and cotton tape		composite carbon black paper and metalized carbon black paper	
Thickness	.1 cm	(.04 inch)	.025 cm	(.01 inch)
Sheath				
Material	Aluminum		Aluminum	
Thickness	.25 cm	(.1 inch)	.48 cm	(.19 inch)
Resistivity	60% IACS		43% IACS	
Jacket				
Material	polyethylene		polyethylene	
Thickness	.33 cm	(.15 inch)	.38 cm	(.15 inch)
Thermal rho	450°C-cm/Watt		450°C-cm/Watt	

Table 6-3 (continued)

	500 kV AC		± 600 kV DC	
Installation				
Depth of Burial	76.2 cm	(30 inches)	76.2 cm	(30 inches)
Completed Cable System				
BIL	1550 kV		1550 kV	
Maximum Temperature across insulation	not applicable		32°C	
Number of Lines Req'd to transmit 10,000 MW	8		4 bipolar	

Table 6-4

500 kV Single-Phase SF_6, GITL, Rigid System Design

Conductor (AL)	40.6 cm (16.0 in.) OD - 1.8 cm (.7 in.) wall
Enclosure (AL)	66.8 cm (26.3 in.) OD - 1 cm (.406 in.) wall
Coating	Coal tar epoxy or butyl rubber and polyethylene composite
Spacing	3 m (10 ft.) centers
Depth of Burial	76 cm (30 in.)
Ground System	Bonded
BIL	1550 kV
Number of Lines Req'd to Transmit 10,000 MW	3

Table 6-5

500 kV Single-Phase SF_6, GITL, Flexible System Design

Stranded Conductor (AL)	17 cm (6.69 in.) OD - 13 cm (5.12 in.) ID
Conductor Sheath	18 cm (7.09 in.) OD
Enclosure (AL)	54 cm (21.06 in.) OD - .5 cm (.197 in.) wall
Coating	Coal tar epoxy or butyl rubber and polyethylene composite
Spacing	3 m (10 ft.) centers
Depth of Burial	76 cm (30 in.)
Ground System	Bonded
BIL	1550 kV
Number of Lines Req'd to transmit 10,000 MW	5

Table 6-6

500 kV Three-Phase, SF_6, GITL, Rigid System Design

Conductor (AL)	18.3 cm (7.2 in.) OD - 1.8 cm (.7 in.) wall
Enclosure (AL)	101.6 cm (40 in.) ID - .95 cm (.375 in.) wall
Coating	Coal tar epoxy or butyl rubber and polyethylene composite
Spacing	3 m (10 ft.) centers
Depth of Burial	76 cm (30 in.)
Ground System	Bonded
BIL	1550 kV
Number of Lines Required to Transmit 10,000 MW	5

Table 6-7

500 kV Resistive Cryogenic Cable Design

Conductor	
size	5000 mm^2 (9700 kcmil)
material	aluminum
outside diameter	9.1 cm (3.6 in.)
stranding	segmental
Insulation	
material	cellulose paper
thickness	2.34 cm (.92 in.)
thermal rho	625°C-cm/watt
SIC	2.0
Cable Pressure Pipe	
material	Fiber-reinforced plastic (FRP)
thickness	1.3 cm (.5 in.)
inside diameter	41.2 cm (16.2 in.)
outside diameter	43.7 cm (17.2 in.)
Thermal Insulation	
foam thickness	15.2 cm (6 in.)
outside diameter	74.2 cm (29.2 in.)
Electromagnetic Shield	
material	aluminum
wall thickness	.38 cm (.15 in.)
inside diameter	74.2 cm (29.2 in.)

Table 6-7 (Continued)

Coating	
type	somastic
thickness	1.3 cm (1/2-in.)
Completed Cable System	
BIL	1550 kV
Number of Lines Required to Transmit 10,000 MW	4
Liquid Nitrogen Return Pipe	
inside diameter	22.2 cm (8.75 in.)
thickness	1 cm (.375 in.)
foam insulation thickness	15.2 cm (6 in.)

Table 6-8

230 kV Flexible Superconducting Cable

Cable Dimensions

Cable cooling channel bore diameter	8.66 cm (3.4 in.)
Cable inner conductor diameter	9.56 cm (3.76 in.)
Cable outer conductor diameter	12.62 cm (4.96 in.)
Contraction layer diameter	13.13 cm (5.16 in.)
Lead sheath diameter	13.64 cm (5.37 in.)
Overall diameter inc. armor	14.27 cm (5.61 in.)
Cryogenic envelope inner bore	34 cm (13.38 in.)
Thermal insulation thickness	7.5 cm (2.95 in.)
Outer pipe diameter	51 cm (20 in.)
Envelope length (1 section)	20 m (62 ft.)
Weight of 1 section	2,045 kg (4,500 lbs.)

Electrical Design

Number of lines required to transmit 10,000 MW	3
Max. stress at nominal voltage, MV/m	10
Continuous rated power, MVA per circuit (base value)	5,100
Rated continuous current, kA (base value)	12.8
Rated continuous surface current density, A/cm	425
SIC (ε_r)	2.2
Dissipation factor, rad	10

Table 6-8 (Continued)

Completed Cable System

Current-dependent loss at continuous contingency rating (5100 MVA)	424 W/km per circuit
Current-dependent loss at normal rating (3500 MVA)	137 W/km per circuit
Dielectric loss	88 W/km per circuit
Envelope heat in-leak	460 W/km per circuit
No. of refrigerators per circuit	2

Table 6-9

230 kV Superconducting Cable - Rigid System

Cable Dimensions		
Conductor O.D.	11.6 cm	(4.6 in.)
Sheath O.D.	31.4 cm	(12.4 in.)
Cryogenic Envelope I.D.	73 cm	(28.75 in.)
Cryogenic Envelope O.D.	90.8 cm	(35.75 in.)
Conductor - Materials	Niobium, Copper, Invar	
Cryogenic Envelope Length	16.5 m	
Completed Cable System		
BIL	870 kV	
Envelope Heat Inleak at 5°K	571 Watts/km (920 Watts/mile)	
Conductor and Dielectric Losses at 5°K	87 Watts/km (140 Watts/mile)	

Table 6-10

300 kV DC Superconducting Cable Design

Conductor

Material	Nb_3Sn embedded in copper matrix
Size	Inner strands: 43 strands of 2.5 mm diameter Outer strands: 120 strands of 2.2 mm diameter

Dielectric

Material	High-density cellulose paper
Impregnant	Supercritical helium at 16 atm and 10-12 K
Thickness	22.5 mm
Max. Dielectric Stress	20 MV/m

Cable Dimensions

Central Channel Diameter	34 mm (1.3 in.)
I.D. of Dielectric	39.2 mm (1.5 in.)
O.D. of Dielectric	84.3 mm (3.3 in.)
O.D. of Cable	96.9 mm (3.8 in.)
I.D. of Enclosure	109.8 mm (4.3 in.)
O.D. of Enclosure	330.0 mm (13 in.)

Completed Cable System

Number of circuits required to transmit 10,000 MW	3 monopolar
BIL	750 kV
Envelope Heat Inleak	200 Watts/km (322 W/mi.)
Average Losses in Cable	50 Watts/km (80 W/mi.)

7. CABLE REFRIGERATION SYSTEM

7.1 Refrigeration Cycles

The refrigeration cycles used to process nitrogen and helium for circulation in resistive cryogenic and superconducting cable systems are mechanically similar to production facilities engaged in the commercial manufacture of liquefied gases, except that the cable liquefiers are closed-loop units, and have a limited capability for producing large quantities of liquefied gases from a warm start. With cable systems, the central cryogenic facilities are more analogous to refrigeration plants than liquefiers. In these refrigerators, the working fluid, nitrogen or helium, is controlled over a temperature range necessary to extract heat from the cable system, or maintain its superconductivity. The temperature swing from the warm to cold end of the cable system lies in the sensible heat range of the fluid and phase changes within the cable runs are avoided. The methods used for the cryogenic processing of cable coolant fluid within refrigeration plants principally use operations common to the reversed Brayton thermodynamic cycle such as: multistage compression of gaseous coolant, restrained expansion through turboexpanders coupled with staged, counter flow heat exchange and, frequently, throttled through a Joule-Thompson valve to achieve final sub-cooling.

7.2 Auxiliary Refrigeration Plant Equipment

Equipment typically found in the cryogenic refrigeration plant consists of the motor-driven refrigerant compressor, heat exchanger bank, or cold box, plus their associated turboexpanders and pumps. While such an array of equipment constitutes the major portion of the process train, a sizable proportion of station auxiliary equip-

7.2 Auxiliary Refrigeration Plant Equipment (cont'd)

ment is required only to complete the battery limit plant. This includes subsystems for coolant conditioning and purification, vacuum pumping, heat rejection, process control, instrument air, deriming, electrical power, lubrication, and on-site storage of process fluids.

7.3 Line End Equipment

Because the cable coolant systems are closed loops, with the working fluids being reprocessed by the central refrigeration plant on a continuous basis, additional equipment may be located at the far end of the coolant loop to compensate for pressure drop or temperature rise in the circulating fluid.

In two of the superconducting helium-cooled systems examined, line end expanders were placed at the far end of the coolant stream to boost the refrigeration effect before return to the cold box. This was accomplished via restrained expansion through a warm, end-loaded turboexpander. By causing the fluid to perform work through the line end expander, a net cooling of the helium was realized at the sacrifice of available fluid pressure.

In the resistive cryogenic systems studied, the line end stations contain multistage liquid nitrogen recirculation pumps that restore lost fluid head and assist coolant flow back to the central refrigeration station.

7.4 Redundancy of Equipment

A prime concern to the cable system operator is the around-the-clock availability of reserve refrigeration capacity at each refrigeration station. Reserve cooling capacity is needed to meet load contingencies arising from equipment breakdowns, malfunctions, and scheduled maintenance outages.

In nearly every plant operating at cryogenic conditions, the cold side process train components will periodically develop blockages or exhibit diminished heat transfer characteristics from accumulated frozen impurities. Their removal requires warming of the affected system and flushing with clean purge gas. While this has become a routine procedure in cryogenic operations, a cable system operator would need to bring reserve cooling capacity on stream during a defrosting operation.

Excess capacity will also be required during initial cool-down of the cable system or to restore a section of line to service that was warmed to ambient conditions for enclosure or cable repair work.

For the purpose of this study, and to meet the contingencies listed above, all line and terminal cooling plants were sized to include one complete refrigeration train in excess of the requirements to operate the 10,000 MVA circuit under normal conditions. This requirement provided a 33% reserve cooling capacity with the three-line system, and 25% reserve with the four-line system.

7. CABLE REFRIGERATION SYSTEM

7.4 Redundancy of Equipment (cont'd)

Where systems include the use of turboexpanders or cryogenic pump at the end of coolant loops, a 100% reserve capacity was specified. These components are expected to require a relatively high level of maintenance in continuous cryogenic service. Prudent design practice points toward installing one complete spare unit for every operating expander or pump. The spare would be maintained at cryogenic temperatures and be placed into service quickly following the outage of its operational counterpart.

7.5 Ideal vs. Actual Refrigeration Performance

An important fact common to the cryogenic cable refrigerators surveyed was that they require significant amounts of input power relative to the net refrigeration effect that they transfer to the coolant. The unbalance between power input and output is due to inherent irreversibilities of the thermodynamic processes and is affected by both temperature level and type of coolant used.

Accordingly, an ideal nitrogen refrigerator, operating at $78^{\circ}K$ on a reversed Carnot cycle, would require a power input of 2.85 Watts for each Watt of refrigeration produced (2.85 W/W). Industry sources report actual power requirements for liquid nitrogen (LN_2) units to be 7.8-9.5 W/W, or the equivalent of 36.5% to 30% of the idealized reversed Carnot cycle efficiencies (% Carnot).

7.5 Ideal vs. Actual Refrigeration Performance (cont'd)

In the case of helium refrigerators, power requirements are even more substantial. System designers report actual power requirements of from 550 W/W to 150 W/W with corresponding Carnot values of 10.7-26.0%. Increased power requirements, with corresponding reductions in Carnot efficiencies were indicated as the design temperature of the circulated helium coolant was lowered.

Table 7-1 presents a summary of refrigeration cycle parameters for three helium-cooled superconducting and one nitrogen-cooled resistive cryogenic system. The Carnot efficiencies listed show general agreement with the trends for such units reported by Strobridge[5,6] in his surveys of commercially-available refrigerator-liquefiers made in 1969 and 1974. However, since the cable system refrigerators tabulated in Table 7-1 represent significant extrapolations in unit capacity and/or process design, indicated cycle efficiencies may be optimistic.

7.6 Refrigeration Plant Descriptions

The refrigeration system design data and operating parameters compiled in this study were acquired through published reports, technical papers, unpublished correspondence, and personal communication with design engineers in the organizations originating the various cable system concepts. The refrigeration plant packages proposed by these sources were in response to a specific requirement that the cable system be capable of carrying 10,000 MVA with appropriate contingency ratings as outlined in Section 4.3 of this report.

7.6 Refrigeration Plant Descriptions (cont'd)

The level of design technology employed to accomplish this goal covered a range of philosophies, from the relatively straightforward scaling up of proven cryogenic cycles, to the development of new cycle designs and equipment requiring state-of-the-art improvements beyond existing technology. A considerable amount of data concerning the design of such refrigeration cycles for cryogenic cable systems has been published under ERDA-funded contracts and should be consulted for additional details[1,2,3,4].

7.6.1. 500 kV Resistive Cryogenic System. This four-line system utilizes liquid nitrogen (LN_2) as a coolant. The basic refrigerators used for cable cooling are rated at 13,478 kW (input) per unit, and each services 15.0 km (9.3 mi.) of cable enclosure. Each line requires seven refrigerators to maintain the LN_2 temperatures in the range of 65°-88°K predicted for normal operation. Seven additional refrigerators, representing 25% reserve capacity would be installed to ensure system reliability. Therefore, the entire refrigeration plant network for the 500 kV RC system consists of thirty-five refrigeration units having a total input power of 471.7 MW, including 94.3 MW allocated as reserve cooling capacity. The thirty-five refrigerators, plus all auxiliary station equipment, would be located in four buildings located along the cable right-of-way and at intervals indicated in Figure 7-1.

7. CABLE REFRIGERATION SYSTEM

7.6 Refrigeration Plant Descriptions

7.6.1 500 kV Resistive Cryogenic System (cont'd)

In addition to refrigeration units, LN_2 pumps, rated at 3.03 cubic meters/minute (800 gpm) are located at the end of each 15.0 km (9.3 mi.) cable from the line end to the refrigeration plant. Seven recirculating pumps would be in continuous service for each of the four lines, maintaining cable coolant pressure in a 0.61-0.82 MPa (88-118 psi) range.

Supplementing these twenty-eight pumps is a complete 100% reserve contingent of twenty-eight pumps installed and maintained at cryogenic temperatures for backup service. As shown in Figure 7-1, all fifty-six pumps would be located in three stations along the cable route and at the two terminal substations. An additional complement of fifty-six pumps are also located within the line refrigeration stations.

The refrigeration cycle proposed for this system circulates LN_2 as the cable coolant, but uses neon, in a two-stage expansion process, as an intermediate heat exchange fluid to extract heat from the LN_2 at each line refrigerator.

7. CABLE REFRIGERATION SYSTEM

7.6 Refrigeration Plant Descriptions

7.6.1 500 kV Resistive Cryogenic System (cont'd)

There are no prototypes of this refrigeration concept in commercial operation. Its designers estimate actual power requirements at 7.8 Watts input per Watt of refrigeration produced. This value corresponds to a Carnot efficiency of 37.0% calculated at a $77^{o}K$ cycle temperature, $300^{o}K$ ambient.

7.6.2 230 kV Superconducting Cable System. This three-line system utilizes dense helium gas as a coolant. The basic refrigerators used for cable cooling are rated at 10,560 kW (input) per unit, and each services 53.1 km (33.0 mi.) of cable by sending a helium stream 26.55 km (16.5 mi.) in opposite directions, through the cryo-enclosure. Each line uses two refrigerators to maintain the helium temperatures between the 6.7^{o}-$8.5^{o}K$ required for superconductivity. Two additional refrigerators, representing 33% reserve capacity, are installed for system reliability and accelerated cool-down operations.

In addition to refrigeration units, turboexpanders are placed at the far end of each coolant loop, midway between refrigeration stations where the helium coolant reverses its flow direction. The line end units serve to lower the temperature of the helium by causing the fluid to perform work in passing through the expander.

7. CABLE REFRIGERATION SYSTEM

7.6 Refrigeration Plant Descriptions

7.6.2 230 kV Superconducting Cable System (cont'd)

The work is unrecovered and allowed to dissipate as heat at the compression end of the turboexpander. However, the process accomplishes the important effect of reducing the helium temperature prior to its return flow to the refrigeration station.

With the 230 kV SC system, each line end expander passes 1.416 kg/sec. (0.644 lb./sec.) of helium on a continuous basis. The pressure drop across each unit is 0.83 MPa (125 psi), resulting in a corresponding temperature decrease of from 7.25°K to 6.42°K between the inlet and exhaust. Approximately 2,157 Watts of heat are dissipated in the process. Four expanders would be in continuous service on each of the three lines.

Supplementing these units is a 100% reserve contingent of twelve expanders installed and maintained at cryogenic temperatures for backup service. As shown in Figure 7-2, the twenty-four expanders would be located in a mid-span station along the cable route and at both terminal substations.

System designers estimate that the refrigeration cycle will require 200 Watts of power input per Watt of refrigeration produced. This value corresponds to a Carnot efficiency of 26.0% calculated at a 5.65°K cycle temperature, 300°K ambient.

7. CABLE REFRIGERATION SYSTEM

7.6 Refrigeration Plant Descriptions

7.6.2 230 kV Superconducting Cable System (cont'd)

Cable refrigerators of the size proposed for this system have yet to be built and operated. However, proponents of the cycle are operating a 500-Watt output, supercritical helium refrigerator that is claimed to be an initial step toward the development of a utility-sized unit.

The refrigeration cycle has been described as a hybrid Claude/Reversed Brayton cycle. Principal components of the refrigeration train include a 261 kW (350 HP) oil-injected screw compressor and three high-speed, gas-lubricated turboexpanders. The cycle maintains coolant temperatures in the 6^{o}-8^{o}K range.

7.6.3 230 kV Superconducting Rigid Cable System. This three-line system circulates helium as a coolant. The basic refrigerators used for cable cooling are rated at 6,406 kW (input) per unit; each services 17.7 km (11 mi.) of cable by sending a helium stream 8.85 km (5.5 mi.) in opposite directions through the cryoenclosure. Each line uses six refrigerators to maintain the helium temperature between 4.6^{o}-5.1^{o}K required for superconductivity. Six additional refrigerators, representing 33% reserve capacity, are installed for system reliability and accelerated cool-down operations.

7.6.3 230 kV Superconducting Rigid Cable System (Cont'd)

The entire refrigeration plant network for the 230 kV SC-R system consists of twenty-four units having a total input power rating of 153.74 MW, including 38.44 MW of reserve cooling capacity. The twenty-four refrigerators, plus all auxiliary station equipment, would be housed in six buildings located along the cable right-of-way, at intervals indicated in Figure 7-3.

System designers classify the refrigeration cycle with the 230 kV SC-R system as both a refrigerator and liquefier. The only fluid processed is helium. In the cycle, helium gas is compressed, cooled to cryogenic temperature by staged expansion through turboexpanders, and finally liquefied by expansion through a Joule-Thompson valve. This process provides a stream of super-critical helium, at 0.69 MPa (100 psi) and 5^{o}K, for conductor cooling plus a source of cold helium for distributed refrigeration to the cable heat shield arrangement used to remove heat leaking into the cryoenclosure. This latter source of helium is bled back to the cold box at ambient temperature.

No line end equipment, such as recirculation pumps or expanders, is required with the system. The circulation of helium through each 8.85 km (5.5 mi.) coolant loop and the heat shield bleed return lines is sustained by the energy generated through the cold box and the suction side of the main helium recycle compressor.

7.6.3 230 kV Superconducting Rigid Cable System (cont'd)

As shown in Table 7-1, the cycle requires a power input of 548 Watts for each Watt of refrigeration produced. This value corresponds to a Carnot efficiency of 10.7% calculated at a 5.0°K cycle temperature, 300°K ambient. While a refrigerator-liquefier cycle of this size has yet to be built commercially, the system designer believes the system can be installed using existing reciprocating compressor and turboexpander technology.

7.6.4 300 kV DC Superconducting Cable System. This three-line system uses helium as a coolant. The refrigerators used for cable cooling are sized at 134, 284, and 375 kW input. Each line has ten 375 kW refrigerators spaced along the line as indicated in Figure 7-4. Terminal refrigeration units are also located at the Energy Park and Mid-Site Substation locations. The input power ratings of the terminal refrigerators are 134 kW and 284 kW, respectively.

In the 300 kV SC-DC system, the line refrigerators split the coolant stream and send it in opposite directions to line end expanders, where these units restore lost refrigeration effect. Due to the relatively low quantity of circulated helium - 94 g/sec. (12.42 lb./min.) - the expander work dissipated as heat at the end of each expansion loop is only 250 W/unit. Helium temperatures are maintained at 10°-12°K throughout the cable envelope. Coolant fluid pressure is held between 0.81-1.62 MPa (117-235 psi).

7.6.4 300 kV DC Superconducting Cable System (cont'd)

The entire refrigeration plant network for the 300 kV SC-DC system consists of thirty-six active refrigerators plus twelve additional units installed to provide a 33% reserve cooling capacity. The total installed input power for the forty-eight refrigerators is 16.67 MW, which includes 4.17 MW of cooling reserve.

All forty-eight refrigerators would be housed in twelve buildings sited along the cable right-of-way at intervals indicated in Figure 7-4. A total of twelve end-of-line expander units would also be sited at four locations on the system. Of these units, sixty-three would be in continuous service, with a complete, cooled-down spare available for each running expander.

The designers of this system estimate that the refrigeration cycle will require 150 Watts of power input per Watt of refrigeration produced. This value corresponds to a Carnot efficiency of 17.5% calculated at an 11°K cycle temperature, 300°K ambient. No commercial prototypes of this system are in operation, but it is believed that the refrigeration cycle design would be similar to the one described for the 230 kV SC system in Section 7.6.2. However, in the case of the 300 kV SC-DC design, the modest 375 kW input power requirement for the refrigerators has already been exceeded by several commercial helium liquefaction plants operating in the United States.

7.7 Refrigeration Plant Costs

7.7.1 Utility Industry Experience. An underlying assumption for this study was that an operating utility would possess no in-house capability for the design and construction of the specialized refrigeration plants associated with the operation of resistive cryogenic and superconducting cable systems. Therefore, the most logical approach would be to contract for these facilities on a turnkey basis, where a qualified engineering construction firm would have prime responsibility for the design, procurement, construction, and start-up of the total cryogenic process train. Such contractual arrangements have become standard practice among utilities that have added liquefied natural gas (LNG) facilities to their systems.

LNG facilities share many technological similarities with cryogenic cable system refrigeration units. The LNG units operate at a nominal temperature of 112°K, and employ compressors, turboexpanders, cryogenic pumps, and fluid purification units in process configurations analogous to the thermodynamic cycles described in Section 7.6

The fact that approximately forty-two LNG plants have been built for the U. S. utility industry in the past seventeen years provides an excellent data base for assessing the financial impact of installing and operating a cryogenic facility within a utility system.

7.7 Refrigeration Plant Costs (cont'd)

7.7.2 Installed Refrigeration Costs. Information used to develop the initial costs of purchasing turnkey cable refrigerator systems originated from such sources as: engineering and construction firms, research and development laboratories, and construction accounting records generated by several LNG plant installations built for utility companies during the period 1969-1972. The overall goal of this work was to establish representative and uniform costing methods that could be applied to the range of refrigerator sizes proposed by the cable system design engineers.

Table 7-2 presents a summary of the estimated, initial installed costs for the superconducting and resistive cryogenic system refrigeration plant networks. Included in the totals are all the cost elements that an operating utility would be expected to incur during the planning, design, construction, and start-up phases of a turnkey installation. This list of installed costs includes:

- Main cryogenic cycle equipment including compressors, cold boxes, and integral expanders.
- All refrigeration cycle subsystems for such functions as: heat rejection, lubrication, purification, vacuum generation, instrument air, and intermediate storage of process fluids.
- Structural steel and interconnecting piping between process subsystems.

7. CABLE REFRIGERATION SYSTEM

7.7 Refrigeration Plant Costs

7.7.2 Installed Refrigeration Costs (cont'd)

- Motor control centers.
- A minimum of two electrical distribution supply circuits at each refrigeration station of sufficient capacity to operate the station on either line.
- Electrical substation equipment to include all transformers, breakers, and switches necessary to serve the plant from multiple feed lines.
- All local and remote, control and monitoring instrumentation.
- Line end equipment, such as turboexpanders and pumps, along with their associated instrumentation.
- Buildings for housing all refrigeration and pumping equipment along the cable right-of-way.
- All equipment, tank, and building foundations.
- Sufficient real estate to erect right-of-way structures and maintain required safety zones along bordering private property.
- Site clearing, grading, and landscaping of refrigerator and pumping station locations.
- Turnkey contractor charges for equipment procurement, field engineering, home office project management, startup expenses, operator training and contractor profit.

7.7.2 Installed Refrigeration Costs (cont'd)

- Project engineering costs incurred by the operating utility during the design, construction, and startup phases of the refrigeration plant contract.
- An overall project contingency of 15%.

Once a reliable, installed cost package was established for a single size of refrigeration unit, the costs for various capacity refrigerators were derived using the "six-tenths factor" logarithmic relationship developed by Williams[7]. This factoring concept is an accepted method for scaling costs of similar equipment in the chemical process industry. The simplified form of the six-tenths factor is:

$$C_n = r^{0.6} C$$

where C_n is the new plant cost, C is the previous plant cost, r is the ratio of the new to previous refrigeration plant (input) capacity. The factor is used to adjust costs for single refrigerators; the system costs in Table 7-2 are multiples of the single unit costs estimated by the six-tenths factor.

One significant result of the cost estimating phase of the study was the realization that the widely-used empirical relationship of Strobridge:

$$C = 7500\ P^{0.7}$$

7.7.2 Installed Refrigeration Costs (cont'd)

where C is the cost in dollars, and P is the input power of the refrigerator in kilowatts, only accounts for approximately 50% of the total first cost of the installation realized by the operating utility. This deviation was predictable, since the Strobridge formula was developed using equipment costs of the basic refrigeration units, exclusive of site development, installation, electrical power facilities, buildings or any of the aforementioned costs incurred by a utility purchasing a large, turnkey refrigerator system.

7.7.3 Capitalized Refrigeration System Costs. Tables 7-3 through 7-6 present the equivalent capital requirements, in 1976 dollars, for the four resistive cryogenic and superconducting cable refrigeration systems, calculated on the basis of the installed systems having a 40-year life expectancy. To derive these costs, it was necessary to assume that capital expenditures of the 20-year life components -- refrigerators, line expanders, pumps, and project engineering -- would be made at initial installation, and repeated in the twenty-first year of the 40-year life cycle. The remaining items -- real estate, site preparation, foundations, electric service and substations -- are one-time, non-renewable expenditures made at initial installation. The present worth for the 20-year life equipment was calculated using an annual carrying charge rate of 18.0%; 16.3% with the 40-year life cost components.

7.7.3 Capitalized Refrigeration System Costs (cont'd)

A 5% inflation rate and 9¼% interest rate were also used to generate the present worth of all future investments. The annual operating and maintenance charges were estimated at approximately 3% of the total, initial installed costs for all refrigeration systems studied.

7.8 Conclusions

This evaluation of refrigerator technology and economics has produced several important conclusions which may be useful in establishing priorities for future system development:

- Sufficient cryogenic technology presently exists to build and operate a low temperature refrigeration system for cable cooling, although a compromise of cycle efficiency and operating cost may be necessary to reach this goal with existing equipment.
- Future development work, leading toward the production of larger screw and centrifugal compressors, as well as gas-bearing turboexpanders, will be necessary if more efficient refrigeration cycles are to be built.
- Cable refrigeration designers should assign a high priority to reducing the power requirements and improving the efficiencies of their cooling cycles; both areas have a direct bearing on the magnitude of installed capital costs and losses for these systems.

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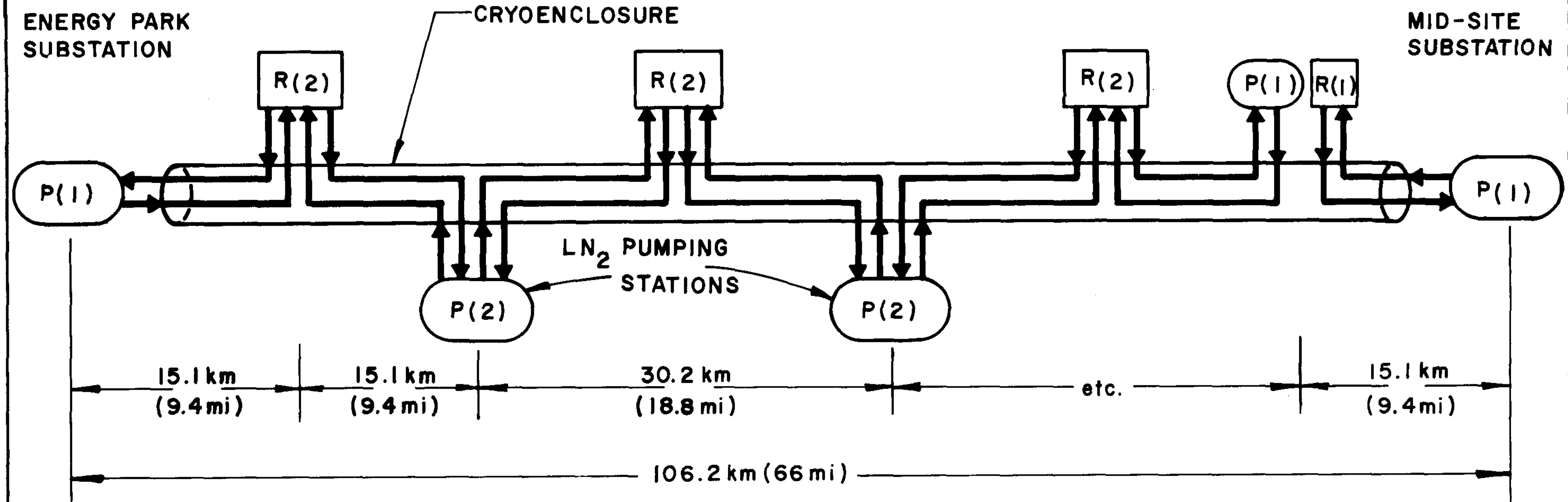
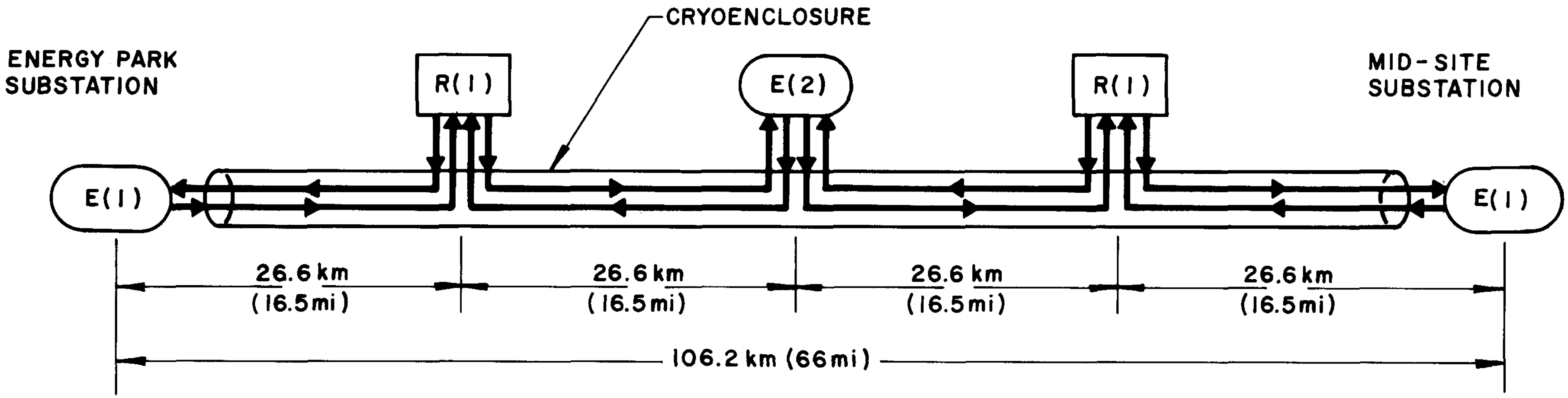


NOTES

CABLE SYSTEM CONSISTS OF 4 LINES WITH 4 REFRIGERATION STATIONS/LINE.
TOTAL SYSTEM CONTAINS 35 REFRIGERATION UNITS; 28 ACTIVE, 7 SPARES PLUS 112 PUMPS; 56 ACTIVE, 56 SPARES IN 5 PUMPING AND 4 REFRIGERATION STATIONS.
COOLING LOOPS REVERSE FLOW DIRECTION AT PUMPING STATIONS.
R(X), P(X), DENOTES NUMBER OF REFRIGERATORS OR PUMPS AT STATION.

HYDRAULIC SCHEMATIC FOR ONE LINE
500 kV RESISTIVE CRYOGENIC CABLE

FIG. 7-1



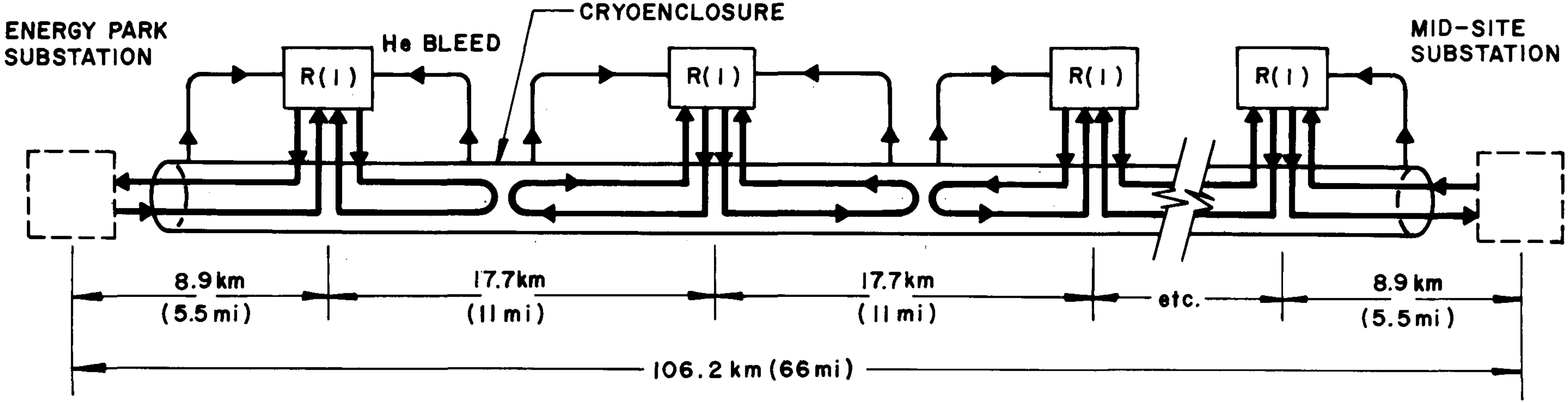
NOTES

CABLE SYSTEM CONSISTS OF 3 LINES WITH 2 REFRIGERATION STATIONS/LINE.
TOTAL SYSTEM CONTAINS 8 REFRIGERATION UNITS; 6 ACTIVE, 2 SPARES
PLUS 24 EXPANDERS; 12 ACTIVE, 12 SPARES IN 3 EXPANDER STATIONS.
COOLING LOOPS REVERSE FLOW DIRECTION AT EXPANDER STATIONS.
BOTH SUBSTATIONS INCLUDE LINE END EXPANDERS.
R(X), E(X), DENOTES NUMBER OF REFRIGERATORS OR EXPANDERS AT STATION.

HYDRAULIC SCHEMATIC FOR ONE LINE

230 kV SUPERCONDUCTING CABLE

FIG. 7-2



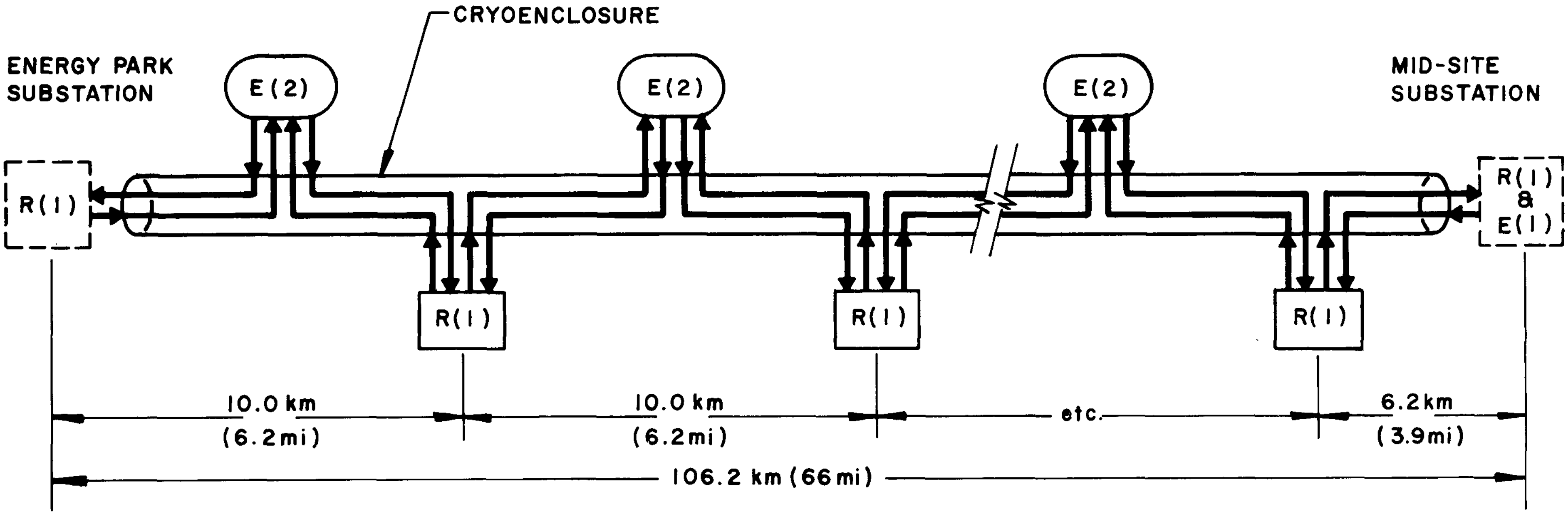
NOTES

CABLE SYSTEM CONSISTS OF 3 LINES WITH 6 REFRIGERATION STATIONS/LINES.
TOTAL SYSTEM CONTAINS 24 REFRIGERATION UNITS; 18 ACTIVE, 6 SPARES.
COOLING LOOPS REVERSE FLOW DIRECTION AT MIDSPAN.
HELIUM BLEED RETURN LINES ARE EXTERNAL TO CRYOENCLOSURE.
R(X) DENOTES NUMBER OF REFRIGERATORS AT STATION.

HYDRAULIC SCHEMATIC FOR ONE LINE

230kV SUPERCONDUCTING RIGID CABLE

FIG. 7-3



NOTES

CABLE SYSTEM CONSISTS OF 3 LINES WITH 10 LINE AND 2 TERMINAL REFRIGERATION STATIONS/LINE.

TOTAL SYSTEM CONTAINS 48 REFRIGERATION UNITS; 36 ACTIVE, 12 SPARES PLUS 126 EXPANDERS; 63 ACTIVE, 63 SPARES IN 11 EXPANDER STATIONS.

COOLING LOOPS REVERSE FLOW DIRECTION AT EXPANDER STATIONS.

MID-SITE SUBSTATION UNIT INCLUDES LINE END EXPANDER EQUIPMENT.

R(X), E(X), DENOTES NUMBER OF REFRIGERATORS OR EXPANDERS AT STATION.

HYDRAULIC SCHEMATIC FOR ONE LINE

300 kV DC SUPERCONDUCTING CABLE

FIG. 7-4

Table 7-1

Refrigeration Plant Design Summary

	CABLE SYSTEM			
System Parameters	230 kV Superconducting	230 kV Superconducting Rigid System	300 kV DC Superconducting	500 kV Resistive Cryogenic
System Length, km (mi.)	106.2 (66.0)	106.2 (66.0)	106.2 (66.0)	106.2 (66.0)
No. Lines/System	3	3	3	4
No. Refrigerators/Line	2	6	12	7
No. Refrigerators/System	8(a)	24(a)	48(a)	35(b)
No. Refrigeration Stations/System	2	6	12	4
Design Input Power/Refrigerator, kW				
Line Refrigerator	10,560	6,406	375	13,478
Mid-Site Refrigerator	-	-	284	-
Energy Park Refrigerator	-	-	134	-
Installed Input Power/Refrig. Station, MW(c)				
Line Station	46.46	28.19	1.65	74.13/37.06(g)
Mid-Site Station	-	-	1.25	-
Energy Park Station	-	-	0.59	-
Normal System Input Power, MW(c)	69.7(d)	126.8(d)	13.75(d)	415.1(e)
Installed System Input Power, MW(c)	92.93	169.1	18.34	518.9
No. Expander Stations/System	3	None	11	None
No. Expanders/System-(Active/Spares) (f)	12/12	-	63/63	-
No. Pumping Stations/System	None	None	None	5
No. Pumps/System-(Active/Spares)	-	-	-	56/56
Refrigeration Cycle Parameters				
Coolant Type	Helium	Helium	Helium	Nitrogen
Coolant Temp. Range, ^{o}K	6.7-8.5	4.6-5.1	10-12	65-89
Coolant Pressure Range, MPa (psi)	0.61-1.52 (88-220)	0.66-0.69 (96-100)	0.81-1.62 (117-235)	0.61-0.82 (88-118)
Watts Input/Watts Refrigeration, Actual	200	548	150	7.8
% Carnot Efficiency (@ ^{o}K)	26.0 (5.65^{o}K)	10.7 (5^{o}K)	17.5 (11^{o}K)	37.0 (77^{o}K)

Notes:

(a) Includes 25% reserve, installed refrigeration capacity.
(b) Includes 20% reserve, installed refrigeration capacity.
(c) Includes 10% addition for powering station auxiliary equipment.
(d) System input under normal conditions, 10,000 MW load level, 3 lines operating.
(e) System input under normal conditions, 10,000 MW load level, 4 lines operating.
(f) Excludes expander equipment with cold box process train.
(g) System includes one, half-size station.

Table 7-2

SUMMARY OF INITIAL INSTALLED COSTS
CABLE REFRIGERATION SYSTEMS

Cost Component[a]	CABLE SYSTEM: 230 kV Superconducting K$	230 kV Superconducting Rigid System K$	300 kV Superconducting K$	500 kV Resistive Cryogenic K$
Real Estate[b]	480	545	992	800
Site Preparation and Foundations[b]	4,636	10,320	3,804	23,510
Buildings[b]	7,340	16,347	6,039	21,170
Refrigeration Equipment[c]	76,047	168,986	62,269	394,318
Pumping Stations[c]	-	-	-	2,300
Expander Stations[c]	1,115	-	2,318	-
Electric Service and Substations[b]	6,541	14,617	5,815	19,470
Project Engineering[c]	4,939	13,696	5,210	32,180
Subtotal, 20-yr. life components	$ 82,101	$182,682	$ 69,797	$428,798
Subtotal, 40-yr. life components	18,997	41,829	16,650	61,800
Initial Installed Cost of System	$101,098	$224,511	$86,447	$490,598

Notes

(a) All costs calculated as of January 1, 1976
(b) Cost component having estimated 40-year life
(c) Cost component having estimated 20-year life

Table 7-3

Capital Cost of Refrigeration Plants
230 kV Superconducting Cable System

	Item	Quantity	Material K$	Labor K$	Total K$
I.	Real Estate	6.5 ha.(16 ac)	480	-	480
II.	Site Prep. & Foundations		1,887	2,749	4,636
III.	Buildings	2	2,936	4,404	7,340
IV.	Refrigerators	8	77,065	27,077	104,142
V.	Line Expanders	12	1,222	305	1,527
VI.	Elec. Ser. & Substations	2	2,944	3,597	6,541
VII.	Operation & Maintenance		3,777	11,333	15,110
VIII.	Engineering		-	6,764	6,764
IX.	TOTALS		$90,311	$56,229	$146,540

Notes:

Items I, II, III, and VI are 40-year life components.
Items IV, V, and VIII are 20-year life components.
Item VII calculated at 3% of initial project cost.
Capitalized costs calculated using interest rate of 9¼%,
annual escalation factor of 5%.

Table 7-4

Capital Cost of Refrigeration Plants
230 kV Superconducting Rigid Cable System

	Item	Quantity	Material K$	Labor K$	Total K$
I.	Real Estate	12.1 ha.(30 ac)	545	-	545
II.	Site Prep. & Foundations		4,197	6,123	10,320
III.	Buildings	6	6,539	9,808	16,347
IV.	Refrigerators	24	171,248	60,168	231,416
V.	Elec. Ser. & Substations	6	6,578	8,039	14,617
VI.	Operation & Maintenance		10,338	31,012	41,350
VII.	Engineering		-	18,756	18,756
VIII.	TOTALS		$199,445	$133,906	$333,351

Notes:

Items I, II, III, and V are 40-year life components.
Items IV and VII are 20-year life components.
Item VI calculated at 3% of initial project cost.
Capitalized costs calculated using interest rate of 9¼%, annual escalation factor of 5%.

Table 7-5

Capital Cost of Refrigeration Plants
300 kV DC Superconducting Cable System

	Item	Quantity	Material K$	Labor K$	Total K$
I.	Real Estate	19.4 ha.(48 ac)	992	-	992
II.	Site Prep. & Foundations		1,544	2,260	3,804
III.	Buildings	12	2,415	3,624	6,039
IV.	Refrigerators	48	63,103	22,171	85,274
V.	Line Expanders	63	2,540	635	3,175
VI.	Elec. Ser. & Substations	12	2,617	3,198	5,815
VII.	Operation & Maintenance		3,990	11,960	15,950
VIII.	Engineering		-	7,135	7,135
IX.	TOTALS		$77,201	$50,983	$128,184

Notes:

Items I, II, III, and VI are 40-year life components.
Items IV, V, and VIII are 20-year life components.
Item VII calculated at 3% of initial project cost.
Capitalized costs calculated using interest rate of 9¼%, annual escalation factor of 5%.

Table 7-6

Capital Cost of Refrigeration Plants
500 kV Resistive Cryogenic Cable System

	Item	Quantity	Material K$	Labor K$	Total K$
I.	Real Estate	16.6 ha.(41 ac)	800	-	800
II.	Site Prep. & Foundations		2,360	21,150	23,510
III.	Buildings	4	8,468	12,702	21,170
IV.	Refrigerators	35	399,644	140,416	540,060
V.	Nitrogen Pumps	56	2,205	945	3,150
VI.	Elec. Ser. & Substations	4	8,760	10,710	19,470
VII.	Operation & Maintenance		23,565	70,700	94,265
VIII.	Engineering		-	44,070	44,070
IX.	TOTALS		$444,229	$302,266	$746,495

Notes:

Items I, II, III, and VI are 40-year life components.
Items IV, V, and VIII are 20-year life components.
Item VII calculated at 3% of initial project cost.
Capitalized costs calculated using interest rate of 9¼%, annual escalation factor of 5%.
Costs for an additional 56 pumps located at refrigerator sites are included in totals of item IV.

8. HIGH-PRESSURE OIL-FILLED PIPE-TYPE CABLE SYSTEMS

8.1 General

High-Pressure Oil-Filled Pipe-Type (HPOPT) cable is the most commonly used underground system in the United States for 69 kV and higher voltages. Figure 6-1 illustrates the three HPOPT cables within a steel pipe enclosure. Pressurized oil on the cable laminate insulation provides a superior dielectric system.

8.1.1 Self-Cooled Systems. Figure 8-1 is the system schematic for the naturally-cooled 500 kV and 765 kV cable systems. The cable charging current necessitates installations of shunt compensation at three mid-line locations and at the substations. Oil pumping plants are also at these locations to maintain the oil pressure required for the cable insulating system.

Installing the HPOPT cable in the network system described in Chapter 4 required series impedance installed at Energy Park to compensate for network current inflow allowed by the system's relatively low impedance.

8.1.2 Force-Cooled System. Figures 8-2 and 8-3 are system schematics for the force-cooled HPOPT cable systems. Force-cooling is accomplished by pumping refrigerated oil within the pipe and thus cooling the cables by removing the heat losses. The separation of refrigeration plants depends on factors such as flow characteristics and system heat dissipation.

8. HIGH-PRESSURE OIL-FILLED PIPE-TYPE CABLE SYSTEMS

8.1 General

8.1.2 Force-Cooled System (cont'd)

The oil temperature in the system is limited by the earth ambient and the highest temperature of the system is limited by the cable insulation. For the 500 kV and 765 kV systems, the refrigeration plants are 4.4 km (7.1 mi.) and 3.3 km (5.3 mi.) apart, respectively. This design for removing the cable losses by forced cooling results in a 33% reduction in the number of transmission lines for both 500 kV and 765 kV.

The network series impedance requirements are reduced because the overall system impedance is higher than the self-cooled systems due to fewer circuits.

8.2 Material and Installation Costs

The typical trench cross-sectional views are illustrated by Figures 8-3 and 8-4. The installed costs for all material and labor for the three self-cooled systems and the two force-cooled systems are shown in Tables 8-1, 8-2, 8-3, 8-4, and 8-5. The costs were developed from the general installation details given in Section 3.9 and the following.

8. HIGH-PRESSURE OIL-FILLED PIPE-TYPE CABLE SYSTEMS

8.2 Material and Installation Costs (cont'd)

- The material costs for the cable, pipe, and pumping plants were obtained from existing suppliers. Since this is a mature system, the material pricing can be accepted with a high degree of confidence.
- Manholes were used every 1760 feet for splicing.

8.3 Losses

System losses are summarized in Tables 8-6 and 8-7, and are based on the conditions outlined in Section 6.2.

8.4 Cost Summary

The total installed cost for both radial and network HPOPT cable systems is given by Tables 8-8 and 8-9. The capitalized cost of losses represents approximately 25% of the total cost for the self-cooled systems versus approximately 32% of the total cost for the force-cooled systems.

8.5 System Evaluation

8.5.1 General. The 500 kV HPOPT cellulose-insulated cable has been tested at Waltz Mill and is considered to be commercially available. The 500 kV and 765 kV HPOPT PPP-insulated cable is being developed under an EPRI/ERDA-sponsored program.

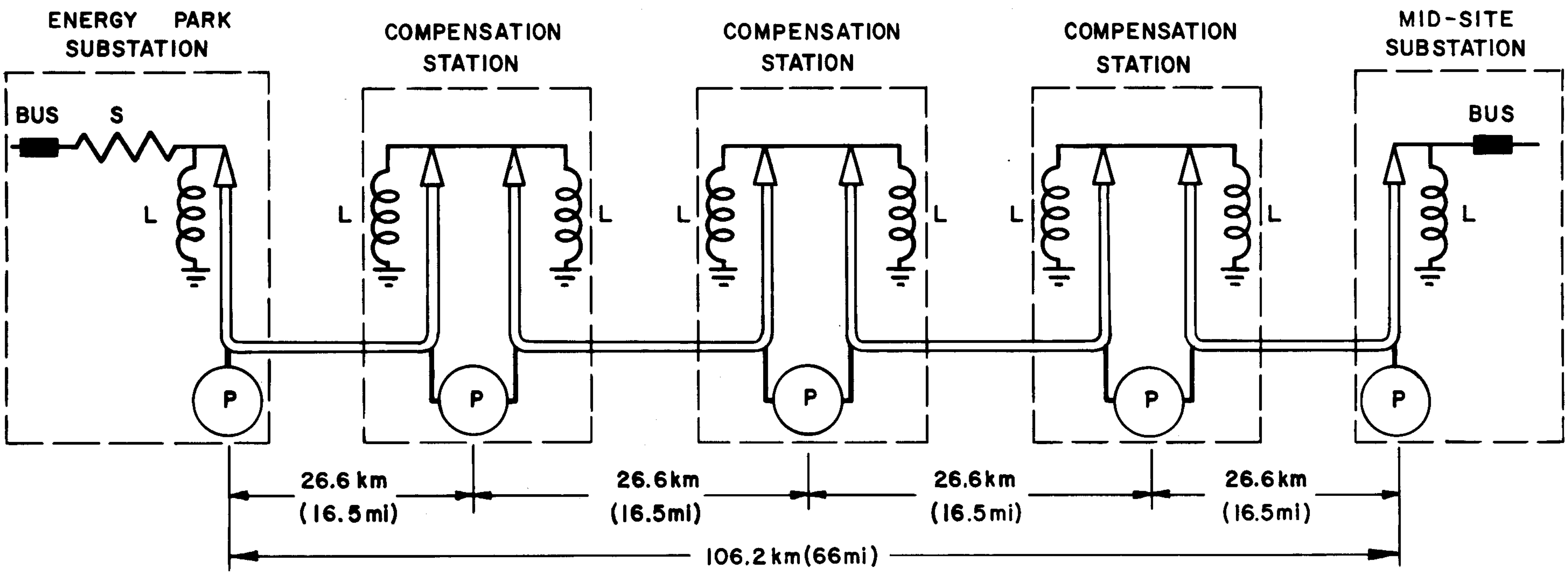
8.5 System Evaluation (cont'd)

8.5.2 Reliability. The 500 kV and 765 kV HPOPT cable should share in the excellent reliability record of the existing HPOPT systems.

8.5.3 Installation. Installation techniques are well developed for HPOPT cable. However, the long time required for taping the splices and terminations may be reduced with premolded splices and terminations. Some innovations have been offered in this area. However, the estimates were based on taped splices and terminations.

8.5.4 Future Developments. Two areas for future development are the reduction of dielectric losses and investigation of moisture migration associated with the earth thermal circuit. The present high insulation losses result from the relatively high dielectric power factor. PPP insulation may reduce the power factor from 0.002 to 0.0005; however, further research and development is needed to combine low thermal resistance, good mechanical and taping properties with a low dielectric power factor.

The ability to thermally evaluate underground transmission systems would be significantly improved with better information on moisture migration under various soil conditions and pipe sizes. This investigation would be of particular value for the larger size pipes or enclosures.

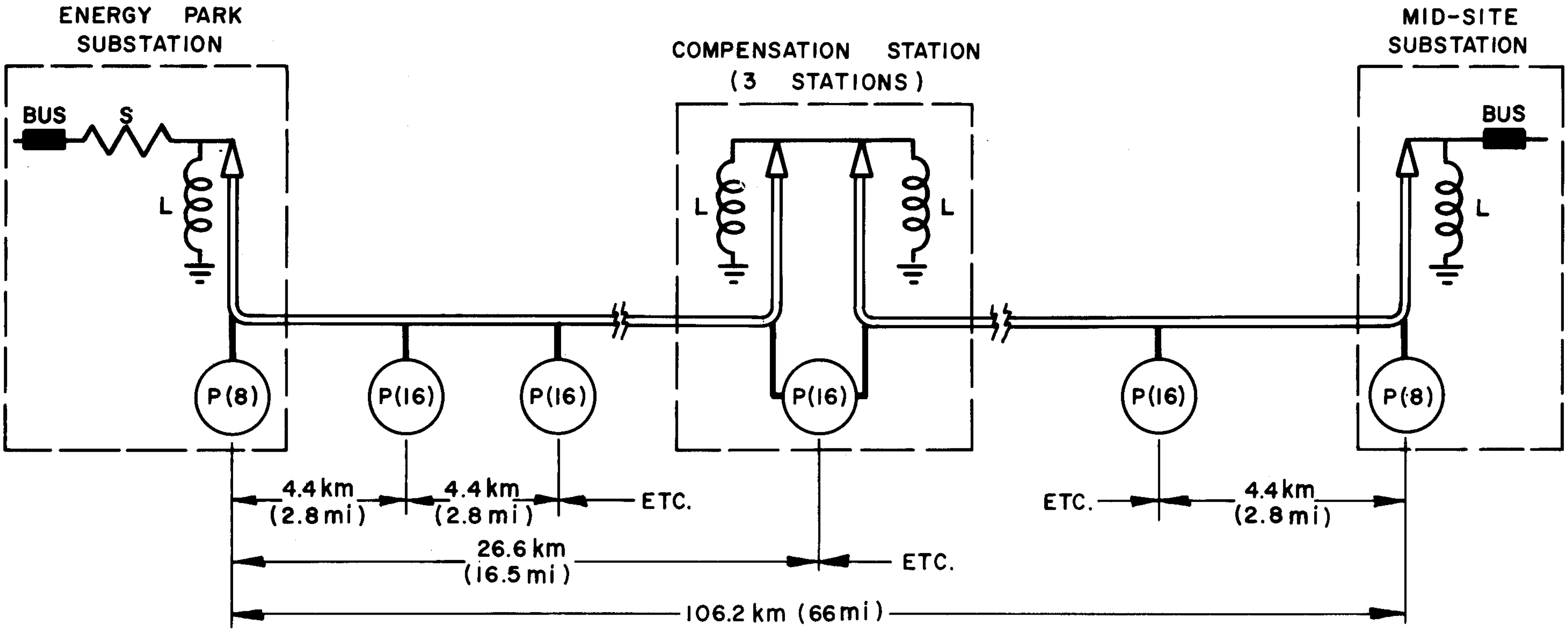


		NO. LINES	NO. PRESSURE UNITS	L-MVAR/ LINE/UNIT	S-OHMS/LINE
500kV HPOPT CELLULOSE-INSULATED	-RADIAL	16	16	270	-
	-NETWORK	16	16	270	22.0
500kV HPOPT PPP-INSULATED	-RADIAL	12	13	246	-
	-NETWORK	12	13	246	13.75
765kV HPOPT PPP-INSULATED	-RADIAL	9	8	438	-
	-NETWORK	9	8	438	18.56

LEGEND
L = SHUNT COMPENSATION UNIT-(MVAR/LINE/UNIT)
S = SERIES COMPENSATION UNIT-(OHMS/LINE)-(INDUCTIVE)
P = DUAL PRESSURE STATION

SYSTEM SCHEMATIC
HPOPT CABLE

FIG. 8-1



LEGEND

L = SHUNT COMPENSATION UNIT (246 MVAR / LINE / UNIT) – (INDUCTIVE)

P(X) = PRESSURE AND COOLING STATIONS (NUMBER OF UNITS AT STATION) – 25 STATIONS
PRESSURE AND COOLING STATIONS SERVE ALL LINES

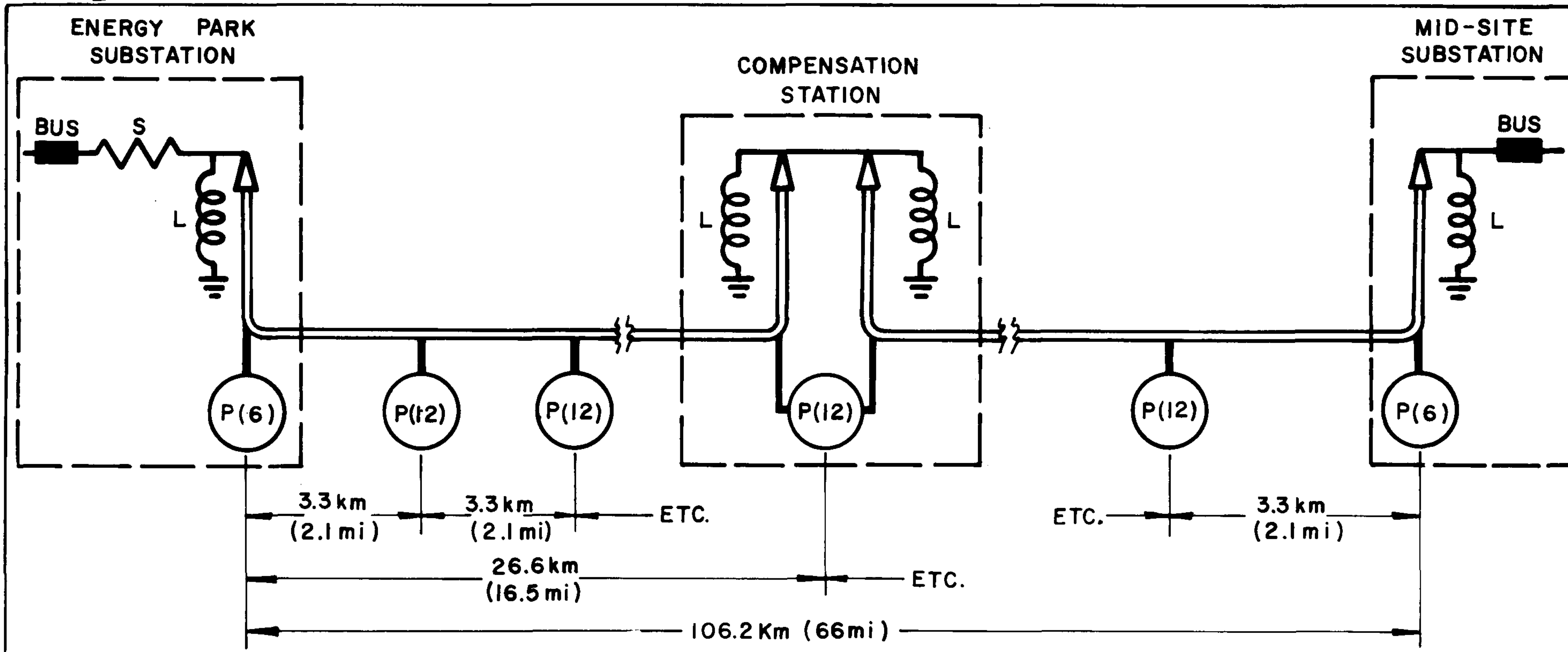
S = SERIES COMPENSATION UNIT
FOR RADIAL SYSTEM, S = 0
FOR NETWORK SYSTEM, S = 3.45 OHMS / LINE – (INDUCTIVE)

SYSTEM SCHEMATIC

500 kV FORCE-COOLED HPOPT PPP-INSULATED CABLE

8 LINES

FIG. 8-2



LEGEND

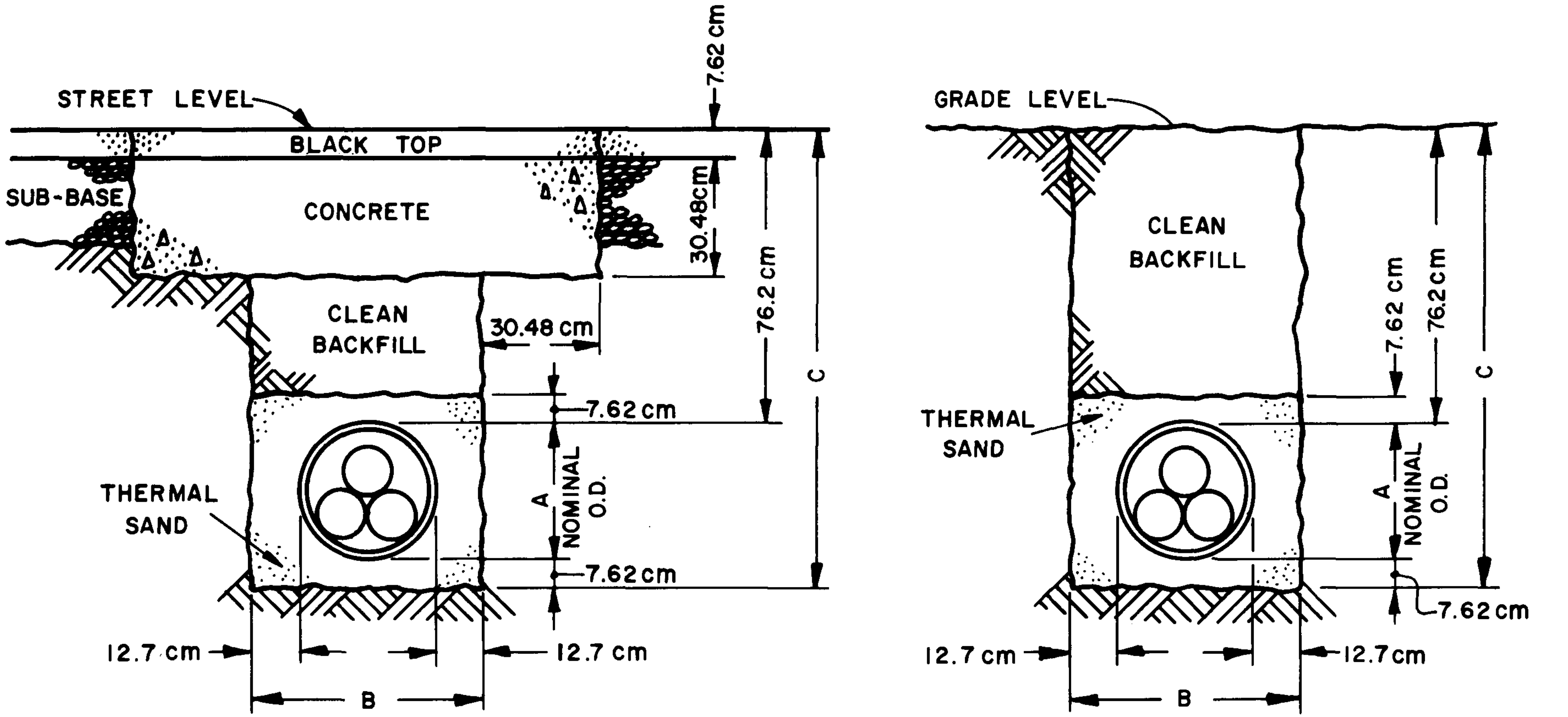
L = SHUNT COMPENSATION UNIT (438 MVAR / LINE / UNIT) – (INDUCTIVE)
P(X) = PRESSURE AND COOLING STATIONS (NUMBER OF UNITS AT STATION) – 33 STATIONS
S = SERIES COMPENSATION UNIT
FOR RADIAL SYSTEM, S = 0
FOR NETWORK SYSTEM, S = 6.39 OHMS/LINE – (INDUCTIVE)

SYSTEM SCHEMATIC

765 kV FORCE-COOLED HPOPT PPP-INSULATED CABLE

6 LINES

FIG. 8-3



STREET RIGHT-OF-WAY

PRIVATE RIGHT-OF-WAY

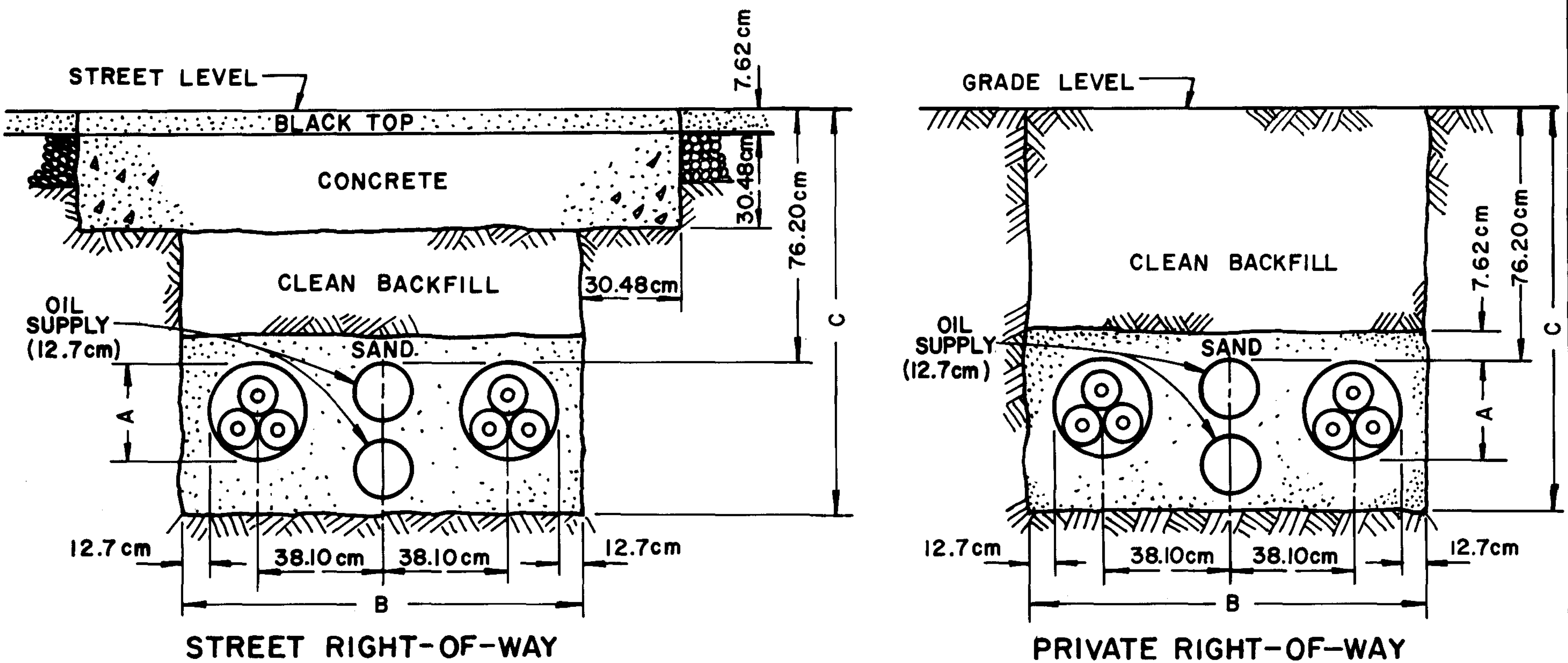
NOTE: TRENCH ℄ SEPARATION IS 3 METERS MINIMUM

DESIGN	A cm	A in	B cm	B in	C cm	C in
500 kV CELLULOSE	34.93	13.75	60.33	23.75	118.75	46.75
500 kV PPP	29.85	11.75	55.25	21.75	113.67	44.75
765 kV PPP	34.93	13.75	60.33	23.75	118.75	46.75

7.62 cm = 3 in
12.70 cm = 5 in
30.48 cm = 12 in
76.20 cm = 30 in

TYPICAL TRENCH CROSS-SECTIONAL VIEW
HPOPT CABLE

FIG. 8-4



NOTE: TRENCH ℄ SEPARATION IS 3.81 METERS (12.5 ft.) MINIMUM.

VOLTAGE	A cm	A in	B cm	B in	C cm	C in
500 kV	29.85	11.75	131.45	51.75	121.92	48
765 kV	34.93	13.75	136.53	53.75	127.00	50

7.62 cm = 3 in
12.7 cm = 5 in
30.48 cm = 12 in
38.10 cm = 15 in
76.20 cm = 30 in

TYPICAL TRENCH CROSS-SECTIONAL VIEW

FORCED-COOLED HPOPT PPP-INSULATED CABLE

FIG. 8-5

Table 8-1

Cable System Cost

500 kV HPOPT Cellulose-Insulated Cable

16 Lines

	Item	Quantity	Material K$	Labor K$	Total K$
I.	Right of Way				
	1. Street	49.8 ha. (123 ac.)	-	-	-
	2. Private	498 ha. (1230 ac.)	21,105	-	21,105
II.	Clearing & Access Roads	498 ha. (1230 ac.)	36	1,264	1,300
III.	Pipe, 32.39 cm (12 3/4 in.) OD				
	1. Street	154.5 km (96 mi.)	5,440	10,362	15,802
	2. Private ROW	1545 km (960 mi.)	54,333	101,933	156,541
IV.	Manholes	3171	17,444	5,233	22,677
V.	Excavation & Backfill				
	1. Street	154.5 km (96 mi.)	4,886	38,359	43,245
	2. Private ROW	1545 km (960 mi.)	9,283	127,590	136,873
VI.	Cable*, 3-1x2500 kcmil	1701 km (1057 mi.)	477,287	44,969	522,256
VII.	Oil in pipe	71.5×10^6 liters (18.9×10^6 gal.)	28,320	2,263	30,583
VIII.	Terminations	128 sets	13,568	2,688	16,256
IX.	Pressure Systems	16	2,064	472	2,536
X.	Engineering			8,480	8,480
XI.	Maintenance (Capitalized)		3,681	8,589	12,270
XII.	Total		638,047	351,877	989,924

*Includes cable and splicing costs

Table 8-2

Cable System Cost

500 kV HPOPT PPP-Insulated Cable

12 Lines

	Item	Quantity	Material K$	Labor K$	Total K$
I.	Right of Way				
	1. Street	38.4 ha. (94.8 ac.)	-	-	-
	2. Private	384 ha. (948 ac.)	16,286	-	16,286
II.	Clearing & Access Roads	384 ha. (948 ac.)	36	984	1,020
III.	Pipe, 27.3 cm (10.75 in) OD				
	1. Street	115.9 km (72 mi.)	3,440	7,250	10,690
	2. Private ROW	1159 km (720 mi.)	34,400	70,900	105,300
IV.	Manholes	2376	13,068	3,920	16,988
V.	Excavation & Backfill				
	1. Street	115.9 km (72 mi.)	3,655	28,717	32,372
	2. Private ROW	1159 km (720 mi.)	6,950	103,200	110,150
VI.	Cable*, 3-1x2500 kcmil	1274 km (792 mi.)	476,950	33,685	510,635
VII.	Oil in pipe	36×10^6 liters (9.5×10^6 gal.)	14,250	1,673	15,923
VIII.	Terminations	96 sets	10,165	2,014	12,179
IX.	Pressure Systems		1,677	384	2,061
X.	Engineering		-	6,360	6,360
XI.	Maintenance (Capitalized)		3,330	7,670	11,000
XII.	Total		584,207	266,757	850,964

*Includes cable and splicing costs

Table 8-3

Cable System Cost

765 kV HPOPT PPP-Insulated Cable

9 Lines

Item		Quantity	Material K$	Labor K$	Total K$
I.	Right of Way				
	1. Street	29.1 ha. (72 ac.)	-	-	-
	2. Private	291 ha. (720 ac.)	12,372	-	12,372
II.	Clearing & Access Roads	291 ha. (720 ac.)	36	756	792
III.	Pipe, 32.39 cm (12 3/4 in.) OD				
	1. Street	86.9 km (54 mi.)	3,060	5,828	8,888
	2. Private ROW	869 km (540 mi.)	30,900	57,154	88,054
IV.	Manholes	1782	9,801	2,940	12,741
V.	Excavation & Backfill				
	1. Street	86.9 km (54 mi.)	2,740	31,538	34,278
	2. Private ROW	896 km (540 mi.)	5,210	77,741	82,951
VI.	Cable*, 3-1x2500 kcmil	956 km (594 mi.)	483,365	30,825	514,190
VII.	Oil in Pipe	37.5×10^6 liters (9.9×10^6 gal.)	14,350	1,400	16,250
VIII.	Terminations	72 sets	12,322	1,870	14,192
IX.	Pressure Systems	8	1,032	236	1,268
X.	Engineering		-	4,770	4,770
XI.	Maintenance (Capitalized)		3,130	7,300	10,430
XII.	Total		578,818	222,358	801,176

*Includes cable and splicing costs

Table 8-4

Cable System Cost

500 kV Force Cooled HPOPT Cable System

8 Lines

		Quantity	Material K$	Labor K$	Total K$
I	Right of Way				
	(a) Street	17 ha. (42 ac)	-	-	-
	(b) Private	170 ha. (420 ac)	7,200	-	7,200
II	Clearing & Access Road	170 ha. (420 ac)	36	555	591
III	Pipe, 10-3/4" OD				
	Street	77.25 km (48 mi)	2,293	4,833	7,126
	Private ROW	772.5 km (480 mi)	22,933	47,267	70,200
IV	Pipe, 5-9/15" OD				
	Street	77.25 km (48 mi)	1,435	3,222	4,657
	Private ROW	772.5 km (480 mi)	14,350	31,511	45,861
V	Manholes - 1 for 2 Pipes	792	5,445	1,634	7,079
VI	Excavation & Backfill				
	Street	38.6 km (24 mi) Trench	1,827	14,360	16,187
	Private ROW	386 km (240 mi) Trench	3,475	51,600	55,075
VII	Cable*, 3 1x2500 kcmil	849.6 km (528 mi)	317,967	22,457	340,424
VIII	Oil in Pipe				
	10-2/4"	24.1×10^6 liters (6.4×10^6 gal)	9,573	1,630	11,203
	5-9/16"	10.9×10^6 liters (2.9×10^6 gal)	4,350	756	5,106
IX	Terminations	64 sets	13,552	2,014	15,566
X	Diffusers	416	1,800	360	2,160
XI	Pressure & Cooling Plants	384	167,408	28,628	196,036
XII	Cooling Plant Maintenance (Capitalized)		12,015	28,036	40,051
XIII	Cable Maintenance (Capitalized)		1,252	2,924	4,176
XIV	Engineering		-	6,000	6,000
			586,911	247,787	834,698

*Includes cable and splicing costs

Table 8-5

Cable System Cost

765 kV Force Cooled HPOPT Cable System

6 Lines

	Item	Quantity	Material K$	Labor K$	Total K$
I	Right of Way				
	1. Street	12.75 ha (31.5 ac)	-	-	-
	2. Private	127.5 ha (315 ac)	5,400	-	5,400
II	Clearing & Access Road	127.5 ha (315 ac)	27	416	443
III	Pipe, 12 3/4" OD				
	1. Street	57 km (36 mi)	2,040	3,885	5,925
	2. Private ROW	570 km (360 mi)	20,600	38,102	58,702
IV	Pipe, 5 9/16" OD				
	1. Street	57 km (36 mi)	1,076	2,417	3,493
	2. Private ROW	570 km (360 mi)	10,760	23,633	34,393
V	Manholes, 1 for 2 Pipes	594	4,084	1,225	5,309
VI	Excavation & Backfill				
	1. Street	29 km (18 mi) Trench	1,598	12,564	14,162
	2. Private ROW	290 km (180 mi) Trench	3,039	45,191	48,230
VII	Cable*, 3-1 x 2500 kcmil	637 km (396 mi)	322,243	20,550	342,793
VIII	Oil in Pipe				
	12 3/4" Pipe	2.48×10^6 liters (6.6×10^6 gal)	9,831	1,231	11,062
	5 9/16" Pipe	8.23×10^6 liters (2.2×10^6 gal)	3,263	570	3,833
IX	Terminations	48 sets	16,443	1,870	18,313
X	Diffusers	360	2,133	427	2,560
XI	Pressure & Cooling Plants	336	147,460	26,021	173,481
XII	Cooling Plant Maintenance (Capitalized)		10,528	24,546	35,074
XIII	Cable Maintenance (Capitalized)		1,261	2,944	4,205
XIV	Engineering		-	6,000	6,000
			561,786	211,592	773,378

*Includes cable and splicing costs

Table 8-6
Losses
HPOPT Cable Systems

	500 kv Cellulose		500 kv PPP		765 kv PPP	
	Radial	Network	Radial	Network	Radial	Network
I **Transmission**						
Total Losses MW (1)	171.14	171.14	133.4	133.4	95.31	95.31
Total MW Hr per year (2)	1,091,600	1,091,600	733,000	733,000	538,600	538,600
Energy Cost per year K$ (3)	19,212	19,212	12,900	12,900	9,479	9,479
Capitalized Energy Cost K$ (4)	117,864	117,864	79,140	79,140	58,157	58,157
Demand Cost K$ (1 & 5)	78,724	78,724	61,364	61,364	43,843	43,843
Sub-Total K$	196,588	196,588	140,504	140,504	102,000	102,000
II **Substations**						
Transformer Losses MW (1)	84.6	84.6	84.6	84.6	103.3	103.3
Total MW Hr per year (2)	521,400	521,400	521,400	521,400	336,370	336,370
Energy Cost per year K$ (3)	9,177	9,177	9,177	9,177	11,200	11,200
Capitalized Energy Cost K$ (4)	56,298	56,298	56,298	56,298	68,712	68,712
Demand Cost K$ (1 & 5)	38,916	38,916	38,916	38,916	47,518	47,518
Sub-Total K$	95,214	95,214	95,214	95,214	116,230	116,230
III **Series Compensation**						
Total Losses MW (1)	None	3,166	None	2.88	None	2.46
Total MW Hr per year (2)		21,317		16,758		14,280
Energy Cost per year K$ (3)		375		295		250
Capitalized Energy Cost K$ (4)		2,301		1,809		1,534
Demand Cost K$ (1 & 5)		1,685		1,325		1,130
Sub-Total K$		3,986		3,134		2,664
IV **Shunt Compensation**						
Total Losses MW (1)	103.7	103.7	70.8	70.8	94.6	94.6
Total MW Hr per year (2)	908,400	908,400	620,200	620,200	828,700	828,700
Energy Cost per year K$ (3)	15,988	15,988	10,915	10,915	14,587	14,587
Capitalized Energy Cost K$ (4)	98,085	98,085	66,962	66,962	89,490	89,490
Demand Cost K$ (1 & 5)	47,702	47,702	32,568	32,568	43,518	43,518
Sub-Total K$	145,787	145,787	99,350	99,350	133,008	133,008
V **Total Capitalized Cost of Energy Losses K$**	437,589	441,575	335,248	338,382	351,238	353,902

Notes

(1) Based on 10,000 MW load level losses.
(2) Based on 9,000 MW and 7,200 MW load levels for 6 months each.
(3) Cost of energy 1.76¢ per KWH.
(4) Capitalized Cost if based on 40 year life and 16.3% Carrying charge rate.
(5) Demand cost is based on $460 per KW required to install the power system capacity to supply the losses.

Table 8-7

Losses

Force Cooled Cable Systems

	500 kV P.P.P.		765 kV P.P.P.	
	Radial	Network	Radial	Network
I Transmission and Cooling				
Total Losses MW (1)	371.1	371.1	280.9	280.9
Total MW Hr per year (2)	2,144,500	2,144,500	1,665,800	1,665,800
Energy Cost per year K$ (3)	37,753	37,753	29,318	29,318
Capitalized Energy Cost K$ (4)	231,552	231,552	179,923	179,923
Demand Cost K$ (1 & 5)	170,706	170,706	129,214	129,214
Sub Total	402,258	402,258	309,137	309,137
II Substations				
Transformer Losses MW (1)	84.6	84.6	103.3	103.3
Total MW Hr per year (2)	521,400	521,400	636,370	636,370
Energy Cost per year K$ (3)	9,177	9,177	11,200	11,200
Capitalized Energy Cost K$ (4)	56,298	56,298	68,712	68,712
Demand Cost K$ (1 & 5)	38,916	38,916	47,518	47,518
Sub Total	95,214	95,214	116,230	116,230
III Series Compensation				
Total Losses MW (1)	None	1.34	None	1.32
Total MW Hr per year (2)	None	7,792	None	7,674
Energy Cost per year K$ (3)	None	137	None	135
Capitalized Energy Cost K$ (4)	None	841	None	828
Demand Cost K$ (1 & 5)	None	616	None	607
Sub Total K$	None	1,457	None	1,435
IV Shunt Compensation				
Shunt Losses MW (1)	47.23	47.23	63.1	63.1
Total MW Hr per year (2)	413,735	413,735	552,756	552,756
Energy Cost per year K$ (3)	7,282	7,282	9,729	9,729
Capitalized Energy Cost K$ (4)	44,675	44,675	59,687	59,687
Demand Cost K$ (1 & 5)	21,726	21,726	29,026	29,026
Sub Total	66,401	66,401	88,713	88,713
V Total Capitalized Cost of Energy Losses K$	563,873	565,330	514,080	515,515

Notes

(1) Based on 10,000 MW load level losses.
(2) Based on 9,000 MW and 7,200 MW load levels for 6 months each.
(3) Cost of energy 1.76¢ per KWH.
(4) Capitalized cost is based on 40 year life and 16.3% carrying charge rate.
(5) Demand cost is based on $460 per KW required to install the power system capacity to supply the losses.

Table 8-8
Cost Summary
HPOPT Cable Systems

Material and Installation*	500 kV Cellulose K$ Radial	500 kV Cellulose K$ Network	500 kV PPP K$ Radial	500 kV PPP K$ Network	765 kV PPP K$ Radial	765 kV PPP K$ Network
Cable System	989,924	989,924	850,964	850,964	801,176	801,176
Substation	142,547	142,547	134,029	134,029	213,933	213,933
Series compensation	None	19,180	None	16,000	None	13,740
Shunt compensation	275,276	275,276	201,037	201,037	263,233	263,233
Sub Total	1,407,747	1,426,927	1,186,030	1,202,030	1,278,342	1,292,082
Losses (Capitalized)						
Cable	196,588	196,588	140,504	140,504	102,000	102,000
Substation	95,214	95,214	95,214	95,214	116,230	116,230
Series compensation	None	3,986	None	3,134	None	2,664
Shunt compensation	145,787	145,787	99,350	99,350	133,008	133,008
Sub Total	437,589	441,575	335,248	338,382	351,238	353,902
Grand Total	1,845,336	1,868,502	1,521,278	1,540,412	1,629,580	1,645,984
Adjusted Grand Total**	1,879,191	1,902,791	1,562,674	1,582,338	1,682,270	1,699,217

*Includes capitalized maintenance costs.

**Based on economic analysis in Section 3

Table 8-9

Cost Summary

Force Cooled Cable System

Material and Installation*	500 kV P.P.P. K$ Radial	500 kV P.P.P. K$ Network	765 kV P.P.P. K$ Radial	765 kV P.P.P. K$ Network
Cable System	834,700	834,700	773,500	773,500
Substation	142,936	142,936	200,076	200,076
Series Compensation	None	8,000	None	8,255
Shunt Compensation	114,305	114,305	174,196	174,196
Sub Total	1,113,031	1,121,031	1,147,772	1,156,027
Losses (Capitalized)				
Cable	402,200	402,200	309,100	309,100
Substation	95,214	95,214	116,230	116,230
Series Compensation	-	1,457	-	1,435
Shunt Compensation	66,401	66,401	88,713	88,713
Sub Total	563,815	565,272	514,043	515,478
Grand Total	1,676,846	1,686,303	1,661,815	1,671,505
Adjusted Grand Total**	1,766,735	1,776,704	1,761,224	1,771,542

*Includes capitalized maintenance costs.

**Based on economic analysis in section 3.

9. SELF-CONTAINED OIL-FILLED CABLE SYSTEMS

9.1 General

Self-Contained Oil-Filled (SCOF) cable is the most commonly used underground cable system in Europe for transmission voltages. This preference in Europe is partly due to the acceptance and economy of direct burial, without an enclosure. High voltage cables in the United States are frequently used in urban areas where there is limited freedom to excavate streets and sidewalks to repair or replace failures. Therefore, HPOPT cables with built-in steel pipe enclosures are preferred in the United States. Figure 6-1 illustrates the internal cross-sectional view of both the AC and DC SCOF cables. Similar to HPOPT cable, this dielectric system is oil pressurized at a nominal 1.38 MPa (200 psi). However, in this case, the oil pressure is imposed on the cable laminate through the 2.54 cm (1.0 in.) channel within the conductor.

9.1.1 AC System. Figure 9-1 is the system schematic for the eight-line 500 kV AC self-contained oil-filled cable (SCOF-AC) system. Similar to HPOPT cable, SCOF-AC cable has a characteristic high charging current that requires shunt compensation at two mid-line locations and at the end substations. Oil pumping plants are also installed at these locations. Section 6.5.1 describes SCOF-AC cable ampacity considerations. When installed in the network system described in Chapter 4, the 500 kV SCOF-AC lines will require series impedance to prevent network current in-flow.

9.1.2 DC System. Figure 9-2 is the system schematic for the four-line 600 kV DC self-contained oil-filled cable (SCOF-DC) system. This system is designed for a bipolar

9. SELF-CONTAINED OIL-FILLED CABLE SYSTEMS

9.1 General

9.1.2 DC System (cont'd)

operation; however, each line can operate in a monopolar mode if one of the cables is inoperative. The design is discussed in Section 6.5.2.

Since this is a direct current system, no series or shunt compensation is required.

9.2 Material and Installation Costs

The typical trench cross-sectional views are illustrated by Figures 9-3 and 9-4. Physical protection from dig-ins is a concern with the SCOF cable and, therefore, a concrete pad is installed over the cable on private right-of-way and a preformed concrete trough is used to protect the SCOF cable in the street.

The installation costs were developed from the general details presented in Chapter 3.

The installed costs for all material and labor for the AC and DC systems are shown in Tables 9-1 and 9-2.

9.3 Losses

System losses are summarized in Tables 9-3 and 9-4, and are based on the general conditions outlined in Section 6.2

9. SELF-CONTAINED OIL-FILLED CABLE SYSTEMS (cont'd)

9.4 Cost Summary

The total installed costs for both radial and network SCOF cable systems are given by Tables 9-5 and 9-6. The capitalized cost of losses represents approximately 17.6% of the total cost for the AC system versus approximately 28.5% of the total cost for the DC system.

9.5 System Evaluation

9.5.1 General. Presently, SCOF cable systems are available only from European cable suppliers in the long lengths required.

9.5.2 Reliability. SCOF cable systems should have reliable performance. However, both systems rely on external bonding and grounding connections that must be inspected periodically and maintained in order to assure continued system reliability.

9.5.3 Installation. Excavation for the SCOF cable systems may present some difficulties when in city streets. The trench must be left open during the time necessary for the cable pull into the trough. The excavation, therefore, must be covered with steel plates or protected with barricades until the cable installation is complete. Some municipalities have placed severe time limitations on street excavations that may restrict this type of installation.

9. SELF-CONTAINED OIL-FILLED CABLE SYSTEMS

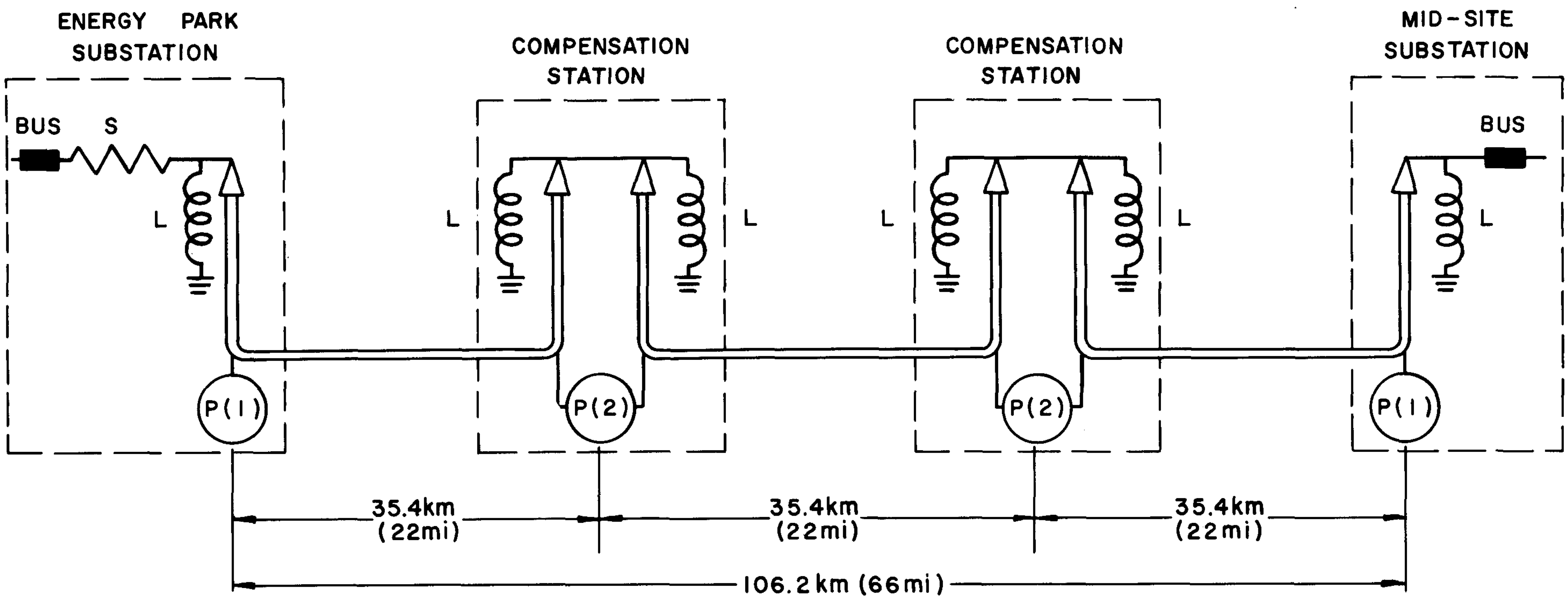
9.5 System Evaluation

9.5.3 Installation (cont'd)

Similar to HPOPT cable, installation techniques are well developed. The long time required for taping splices and terminations encourages development of premolded accessories. The estimates were based on taped splices and terminations.

9.5.4 Future Developments.

Due to the preference of U. S. users for HPOPT cable, SCOF cable is not installed here frequently for transmission lines. Manufacture of long lengths of high voltage SCOF cable would require substantial plant investment by U. S. manufacturers. Excessive dielectric losses are also a concern as with HPOPT cable. Further research and development is needed to combine low thermal resistance, good mechanical and taping properties with low dielectric power factor in the electrical insulation system.



LEGEND

L = SHUNT COMPENSATION UNIT (482.5 MVAR/LINE/UNIT) - (INDUCTIVE)

P(X) = DUAL PRESSURE STATION (NUMBER OF UNITS AT STATION)

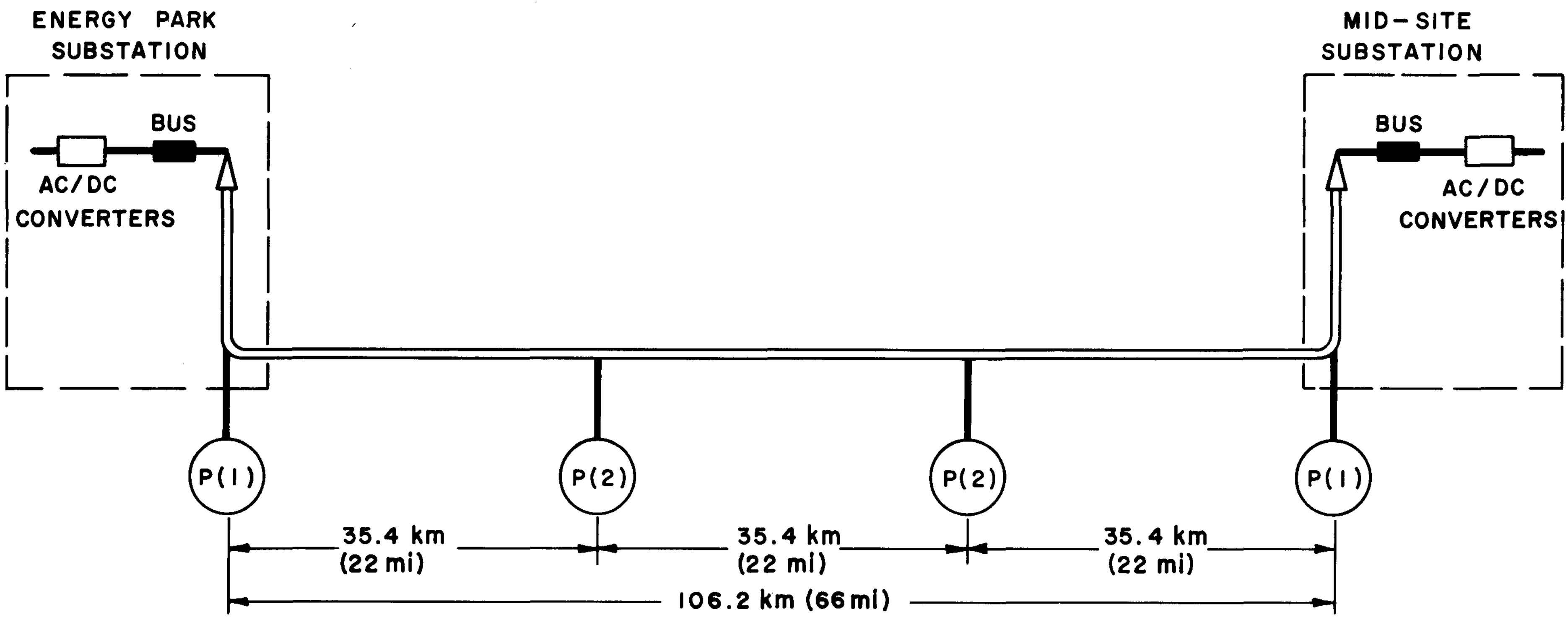
S = SERIES COMPENSATION UNIT
FOR RADIAL SYSTEM, S = 0
FOR NETWORK SYSTEM, S = 12.65 OHMS/LINE - (INDUCTIVE)

SYSTEM SCHEMATIC

500kV AC SELF-CONTAINED OIL-FILLED CABLE

8 LINES

FIG. 9-1



LEGEND

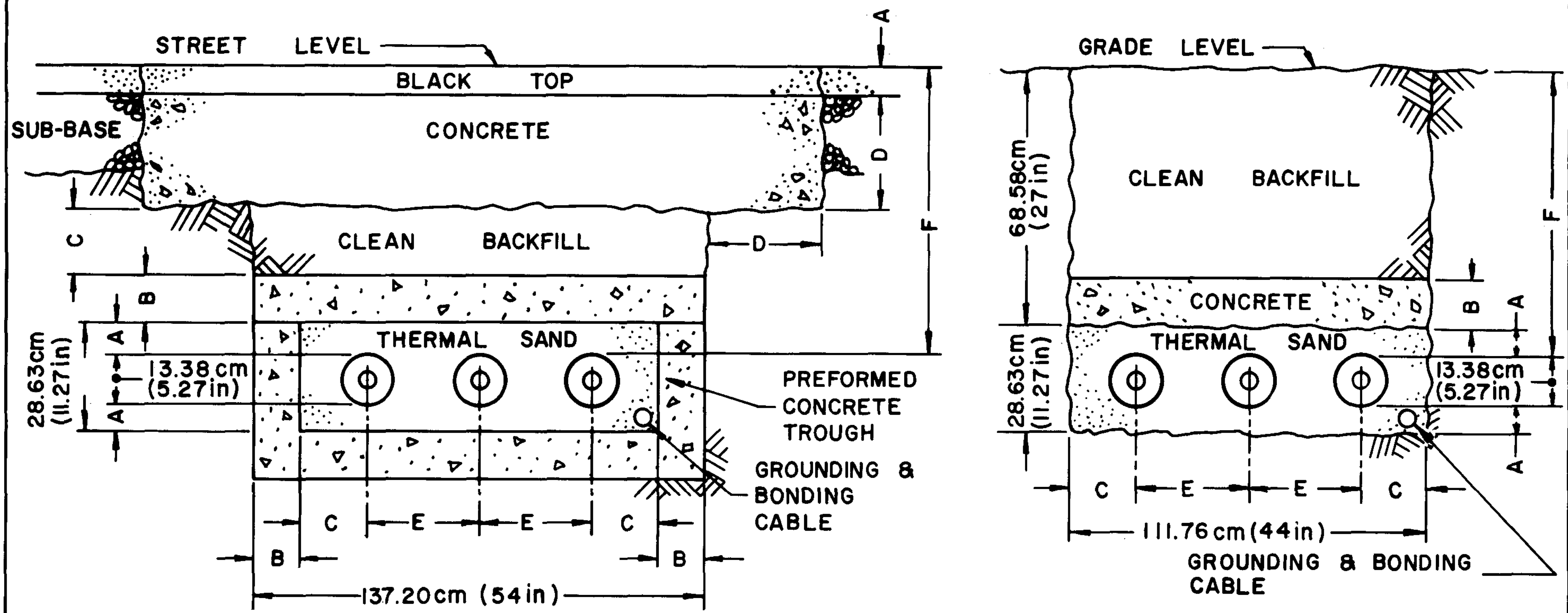
P (X) = DUAL PRESSURE STATION (NUMBER OF UNITS AT STATION)

SYSTEM SCHEMATIC

600kV DC SELF-CONTAINED OIL-FILLED CABLE

4 LINES

FIG. 9-2



STREET RIGHT-OF-WAY

PRIVATE RIGHT-OF-WAY

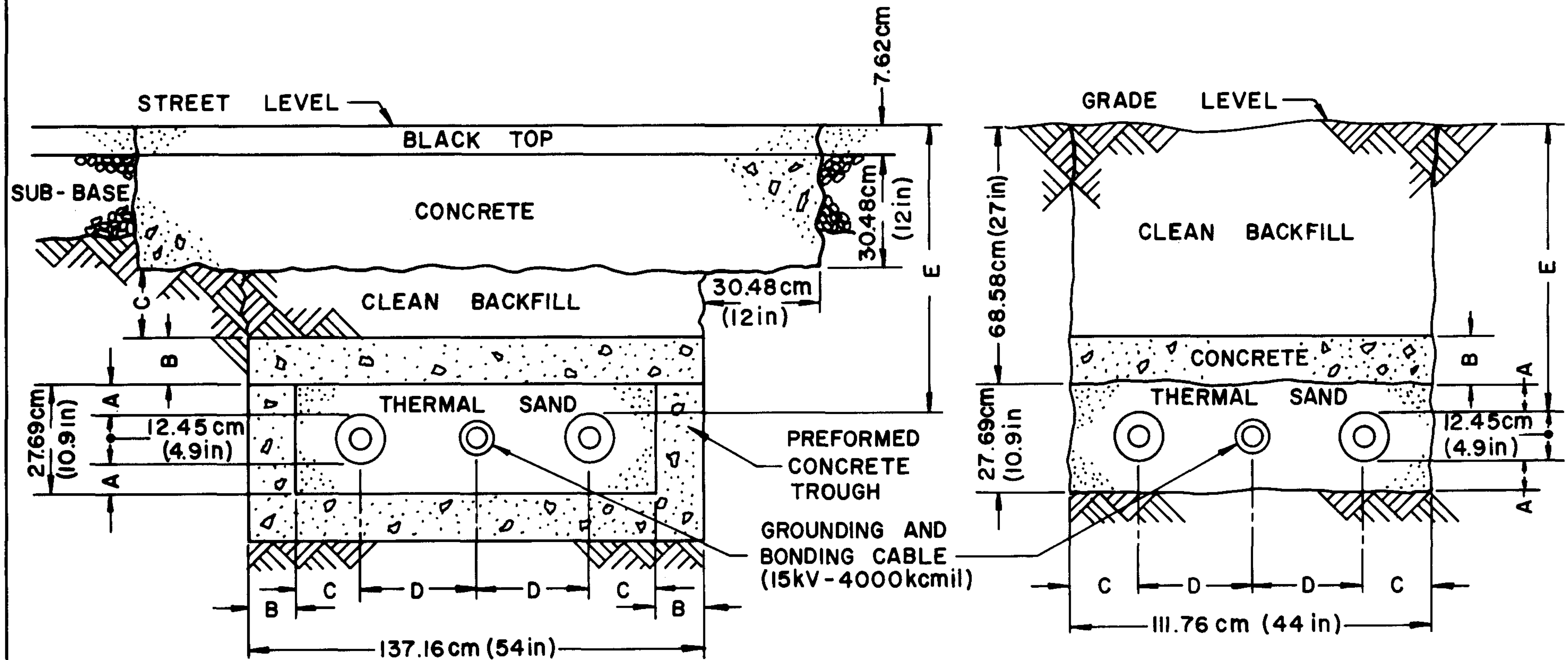
NOTE : TRENCH ℄ SEPARATION IS 3 METERS MINIMUM

A = 7.62 cm (3 in)
B = 12.70 cm (5 in)
C = 17.78 cm (7 in)
D = 30.48 cm (12 in)
E = 38.10 cm (15 in)
F = 76.20 cm (30 in)

TYPICAL TRENCH CROSS-SECTIONAL VIEW

500 kV AC SELF-CONTAINED OIL-FILLED CABLE

FIG. 9-3



STREET RIGHT-OF-WAY

PRIVATE RIGHT-OF-WAY

NOTE: TRENCH ℄ SEPARATION IS 3 METERS MINIMUM

A = 7.62cm (3 in)
B = 12.70cm (5 in)
C = 17.78cm (7 in)
D = 45.72cm (18 in)
E = 76.20cm (30 in)

TYPICAL TRENCH CROSS-SECTIONAL VIEW

600kV DC SELF-CONTAINED OIL FILLED CABLE

FIG. 9-4

Table 9-1

Cable System Cost

500 kV AC Self-Contained Oil Filled Cable

8 Lines

Item	Quantity	Material K$	Labor K$	Total K$
I. Right of Way				
1. Street	26.5 ha. (65.5 ac.)	-	-	-
2. Private	265 ha. (655 ac.)	11,140	-	11,140
II. Clearing & Access Roads	265 ha. (655 ac.)	36	691	727
III. Concrete Enclosure in Street	77.2 km (48 mi.)	2,863	5,115	7,978
IV. Manholes	1584	5,612	2,604	8,216
V. Excavation & Backfill				
1. Street	77.2 km (48 mi.)	5,094	24,688	29,782
2. Private ROW	772 km (480 mi.)	11,672	95,020	106,692
VI. Cable*, 3-1x4930 kcmil	850 km (528 mi.)	631,802	14,750	646,552
VII. Terminations-3 phase	48 sets	4,450	965	5,415
VIII. Pressure Systems - Pumping Plants	6	780	207	987
IX. Engineering		-	3,540	3,540
X. Maintenance (Capitalized)		2,400	5,700	8,100
XI. Total		675,849	153,280	829,129

*Includes cable, splicing and grounding system costs.

Table 9-2

Cable System Cost

600 kV DC Self-Contained Oil Filled Cable

4 Bipolar Lines

Item	Quantity	Material K$	Labor K$	Total K$
I. Right of Way				
1. Street	16.9 ha. (41.8 ac.)	-	-	-
2. Private	169 ha. (418 ac.)	7,174	-	7,174
II. Clearing & Access Roads	169 ha. (418 ac.)	36	454	490
III. Street Concrete Enclosure	36.8 km (24 mi.)	1,572	2,808	4,380
IV. Manholes	792	2,392	1,083	3,475
V. Excavation & Backfill				
1. Street	38.6 km (24 mi.)	2,646	13,163	15,809
2. Private right of way	386 km (240 mi.)	5,898	53,530	59,428
VI. Cable* - 2-1x4000 kcmil	425 km (264 mi.)	183,895	7,028	190,923
VII. Terminations	8 sets	503	113	616
VIII. Pressure system - pumping plants	4	520	138	658
IX. Engineering		-	1,420	1,420
X. Maintenance (Capitalized)		1,215	2,835	4,050
XI. Total		205,851	82,572	288,423

*Includes cable, splices and grounding and bonding system costs.

Table 9-3
Losses
500 kV AC Self-Contained Oil Filled Cable System

		Radial	Network
I	Transmission		
	Total Losses MW (1)	64.82	64.82
	Total MW Hr per year (2)	468,526	468,526
	Energy Cost per year K$ (3)	8,426	8,426
	Capitalized Energy Cost K$ (4)	50,590	50,590
	Demand Cost K$ (1 & 5)	29,816	29,816
	Sub-Total K$	80,406	80,406
II	Substations		
	Transformer Losses MW (1)	84.6	84.6
	Total MW Hr per year (2)	521,400	521,400
	Energy Cost per year K$ (3)	9,177	9,177
	Capitalized Energy Cost K$ (4)	56,298	56,298
	Demand Cost K$ (1 & 5)	38,916	38,916
	Sub-Total K$	95,214	95,214
III	Series Compensation		
	Total Losses MW (1)	None	3.23
	Total MW Hr per year (2)		18,786
	Energy Cost per year K$ (3)		331
	Capitalized Energy Cost K$ (4)		2,030
	Demand Cost K$ (1 & 5)		1,484
	Sub-Total K$		3,514
IV	Shunt Compensation		
	Total Losses MW (1)	34.8	34.8
	Total MW Hr per year (2)	304,848	304,848
	Energy Cost per year K$ (3)	5,365	5,365
	Capitalized Energy Cost K$ (4)	32,916	32,916
	Demand Cost K$ (1 & 5)	16,008	16,008
	Sub-Total K$	48,924	48,924
V	Total Capitalized Cost of Energy Loss K$	224,544	228,058

Notes

(1) Based on 10,000 MW load level losses.
(2) Based on 9,000 MW and 7,200 MW load levels for 6 months each.
(3) Cost of energy 1.76¢ per KWH.
(4) Capitalized Cost is based on 40 year life and 16.3% Carrying charge rate.
(5) Demand Cost is based on $460 per KW required to install the power system capacity to supply the losses.

Table 9-4
Losses
600 kV DC Self-Contained Oil Filled Cable

	Radial	Network
I Transmission		
Total losses MW (1)	36.55	36.55
Total MW Hr per year (2)	212,772	212,772
Energy cost per year K$ (3)	3,744	3,744
Capitalized energy cost K$ (4)	22,974	22,974
Demand cost K$ (1&5)	16,813	16,813
Sub Total K$	39,787	39,787
II Substations		
Transformer losses MW (1 & 6)	297.13	297.13
Total MW Hr per year (2)	2,056,260	2,056,260
Energy cost per year K$ (3)	39,190	36,190
Capitalized energy cost K$ (4)	222,025	222,025
Demand cost K$ (1&5)	136,680	136,680
Sub Total K$	358,705	358,705
III Total Capitalized Cost of Energy Losses K$	398,492	398,492

Notes

(1) Based on 10,000 MW load level losses.
(2) Based on 9,000 MW and 7,200 MW load levels for 6 months each.
(3) Cost of energy 1.76¢ per KWH.
(4) Capitalized cost if based on 40-year life and 16.3% carrying charge rate.
(5) Demand cost is based on $460 per KW required to install the power system capacity to supply the losses.
(6) Includes transformers, valves, filters, smoothing reactors and auxilaries.

Table 9-5

Cost Summary

500 kV AC Self-Contained Oil Filled Cable System

Material and Installation*	Radial K$	Network K$
Cable System	829,129	829,129
Substation	142,876	142,876
Series Compensation	None	11,500
Shunt Compensation	139,240	139,240
Sub Total	1,111,245	1,122,745
Losses (Capitalized)		
Cable	80,406	80,406
Substation	95,214	95,214
Series Compensation	None	3,514
Shunt Compensation	48,924	48,924
Sub Total	225,544	228,058
Grand Total	1,335,789	1,350,803
Adjusted Grand Total**	1,364,795	1,380,140

*Includes capitalized maintenance costs

**Based on economic analysis in Section 3

Table 9-6
Cost Summary
600 kV DC Self-Contained Oil Filled Cable

Material and Installation (1)	Radial K$	Network K$
Cable	288,423	288,423
Substation (2)	663,400	663,400
Sub Total	951,823	951,823
Losses (Capitalized)		
Cable	39,787	39,787
Substation (2)	358,705	358,705
Sub Total	398,492	398,492
Grand Total	1,350,315	1,350,315
Adjusted Grand Total (3)	1,422,628	1,422,628

(1) Includes capitalized maintenance costs.
(2) Includes DC conversion equipment.
(3) Based on economic analysis in Section 3.

10. 500 kV SF_6 GITL SYSTEMS

10.1 General

The GITL systems utilize a spacer-supported conductor in an enclosure pressurized with SF_6 gas to minimize the enclosure size. GITL systems operate as sealed units with a nominal pressure of 0.34 MPa (50 psi) depending on the conductor temperature. The gas must have good electrical and thermal properties and generally sulfur hexafloride (SF_6) is used. Three distinct 500 kV GITL systems are included in the study; a single-phase rigid system, a three-phase rigid system, and a single-phase flexible system. The schematic for the three systems is shown in Figure 10-1.

10.1.1 Rigid Systems. The rigid systems are supplied in 18.3 m (60 ft.) lengths with slip-fit mechanical connectors on aluminum conductors. The aluminum enclosures are designed for butt welding. Expansion and contraction of the conductors is accommodated in the mechanical connections with one spacer rigidly attached to the enclosure and the others free to slide. Expansion of the enclosure is restricted by the backfill. The rigid systems are comparatively inflexible and all bends must be factory assembled.

10.1.2 Flexible System. The recommended design of the flexible system consists of a stranded aluminum conductor in a flexible corrugated enclosure. This system can be shipped in 50 m (164 ft.) lengths on cable reels. The flexible system has obvious advantages in installation but the maximum size and thickness of the enclosure is controlled by mechanical and manufacturing equipment limitations. Joints are mechanical connections similar to the rigid systems.

10. 500 kV SF_6 GITL SYSTEMS

10.1 General

10.1.2 Flexible System (cont'd)

Typical trench cross-sections of the installation of each system are shown in Figures 10-2, 10-3, and 10-4. An internal cross-section of each GITL cable is shown in Figures 6-3, 6-4, and 6-5.

10.2 Material and Installation Costs

The installed costs for all material and labor for the three GITL systems are shown in Tables 10-1, 10-2, and 10-3. The costs were developed from the general installation details given in Section 3.9 and the following.

- The material costs for the preassembled conductor and enclosure including terminations and elbows as required were supplied by the contractor based on costs for these systems under EPRI/ERDA sponsorship.
- The SF_6 gas costs were based on a price of $2.80 per pound which included shipping and storage. The required quantities were calculated. It was assumed that delivery would be made at the filling location for each 762 m (2500 ft.) section and that the sections would be filled as they were completed.

10.3 Losses

The losses for the system are summarized in Table 10-4 and are based on the general conditions outlined in Section 6.2.

10. 500 kV SF_6 GITL SYSTEMS (cont'd)

10.4 Cost Summary

The total installed cost for the three GITL systems for both the radial and network installations is given in Table 10-5. Details on the substation and compensation costs are in Chapter 5.

The capitalized costs of losses represents approximately 12.2%, 11.1%, and 16.4%, respectively, for the three systems studied.

10.5 System Evaluation

10.5.1 General. The single-phase rigid system is commercially available but the single-phase flexible and the three-phase rigid systems are still under development. The individual system designs were supplied by the EPRI/ERDA-sponsored contractors and the conductor sizes were selected to minimize the number of circuits.

Fault locating on GITL systems presents a serious problem since there is no reliable way to locate a fault.

Aluminum pipes have not been widely used in underground applications due to a serious corrosion problem. Studies have indicated that ac potentials on buried aluminum will accelerate corrosion. Therefore, corrosion protection of the aluminum enclosure must receive special attention in buried GITL systems.

10. 500 kV SF_6 GITL SYSTEMS

10.5 System Evaluation (cont'd)

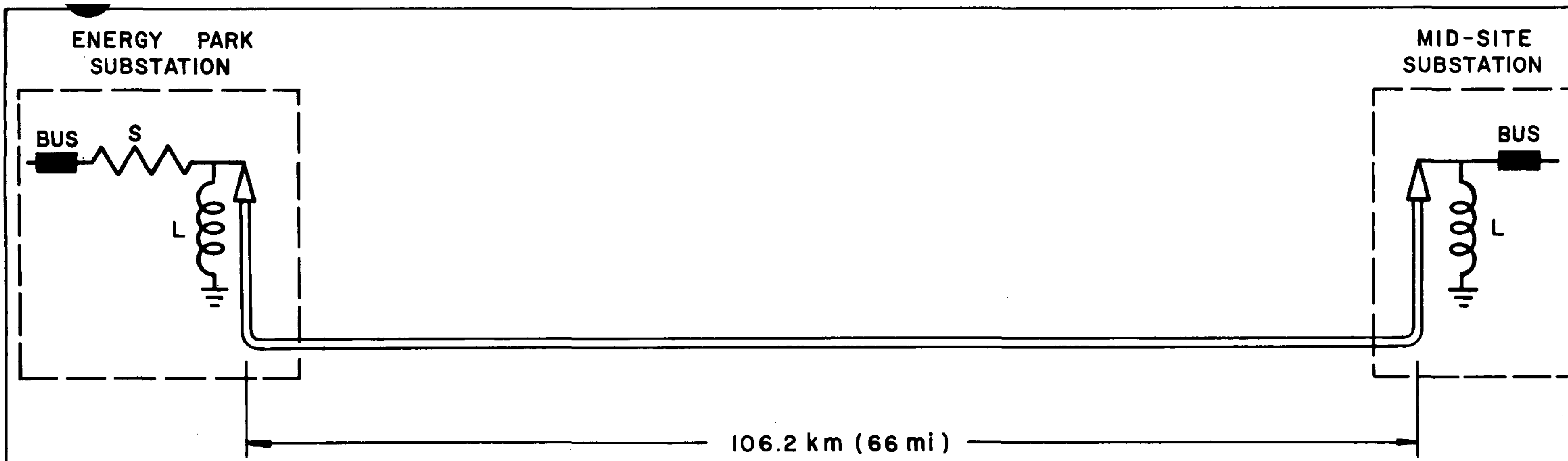
10.5.2 Reliability. In long transmission lines such as the one in this study, a fault could generate and spread contamination which could result in an outage and, therefore, techniques must be developed to prevent contamination during installation and to facilitate its removal after a fault or a breach in the enclosure.

10.5.3 Installation. The rigid systems present some unique installation problems due to the fact that the elbows are factory assembled and every bend must be predetermined. This could be overcome by a large inventory of elbows or an elbow that could be field fabricated.

No serious installation difficulties are anticipated with the flexible system. It should be noted that, if the ratings of the single-phase rigid and flexible GITL systems were the same, a combination of the two would produce a more economical installation.

10.5.4 Future Development. The problems of contamination and fault location should be given priority in new development work on GITL systems.

The inherent high temperature capability of the GITL systems makes desirable the investigation and definition of the earth thermal circuit and limitations, especially for large diameter pipes.



		NO. LINES	L-MVAR/LINE/UNIT	S-OHMS/LINE
SINGLE-PHASE RIGID SYSTEM	- RADIAL	3	190	-
	- NETWORK	3	65	3.75
SINGLE-PHASE FLEXIBLE SYSTEM	- RADIAL	5	-	-
	- NETWORK	5	-	4.25
THREE-PHASE RIGID SYSTEM	- RADIAL	5	-	-
	- NETWORK	5	-	4.00

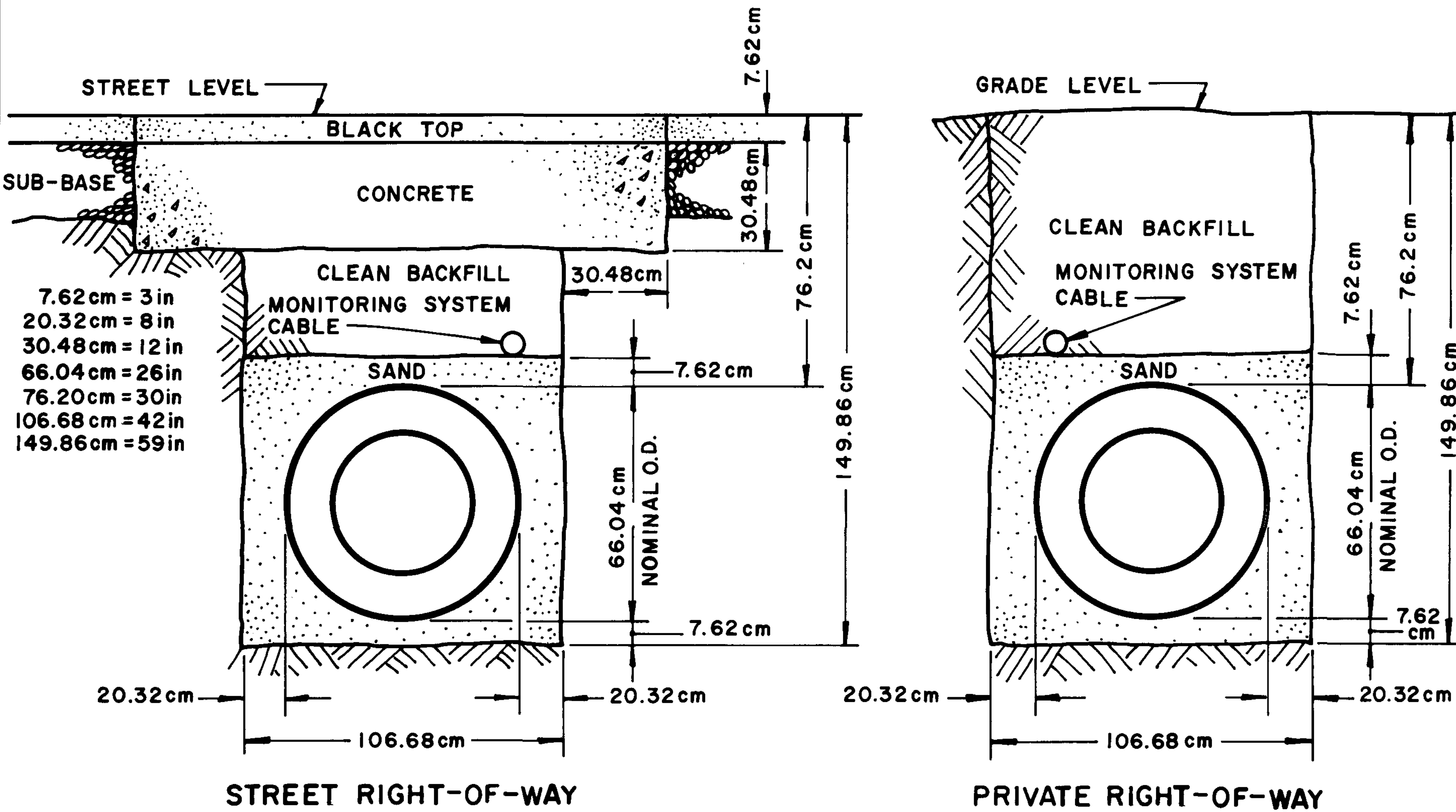
LEGEND

L = SHUNT COMPENSATION UNIT (MVAR/LINE/UNIT)

S = SERIES COMPENSATION UNIT (OHMS/LINE)-(INDUCTIVE)

SYSTEM SCHEMATIC
500kV SF_6 GITL

FIG. 10-1



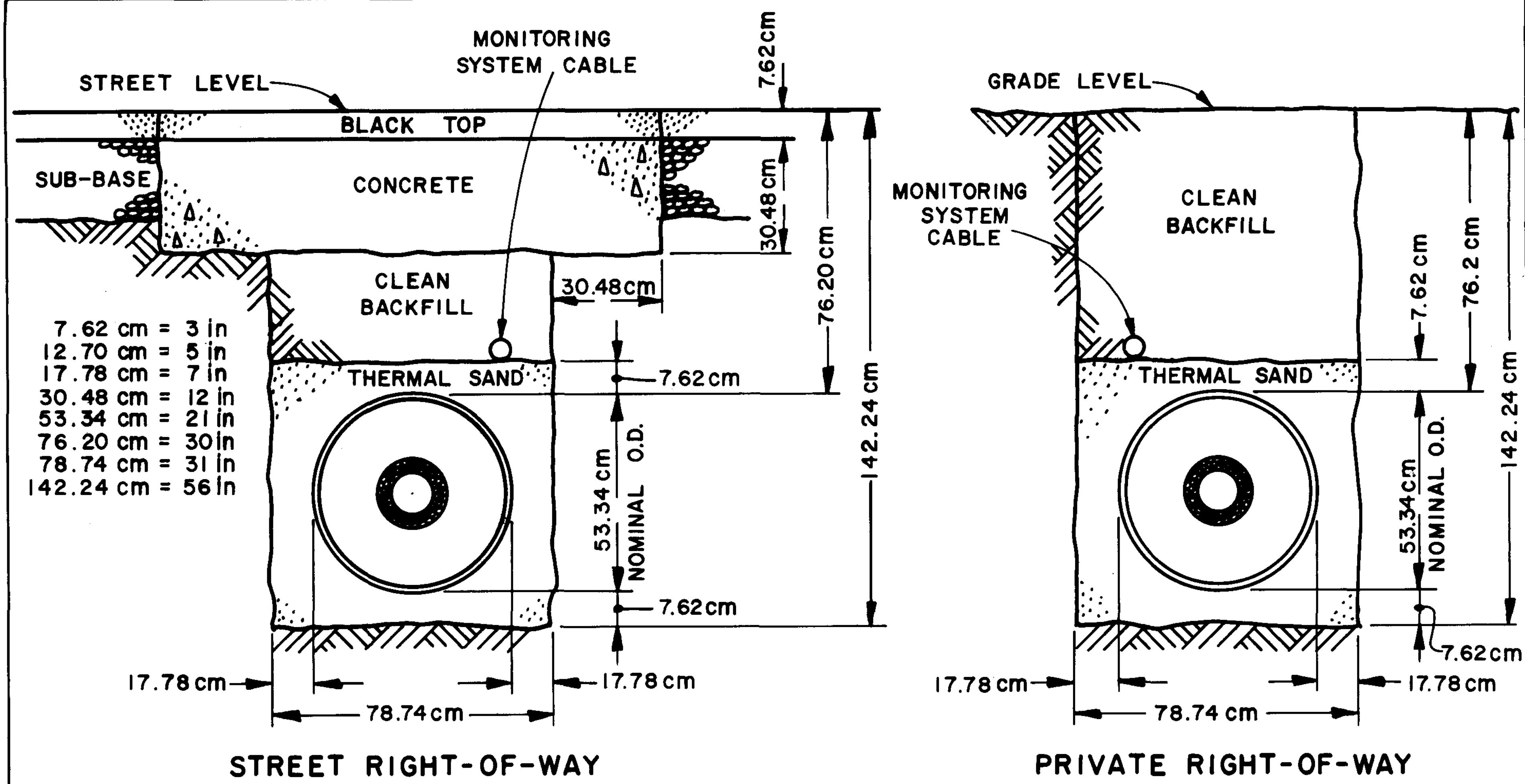
NOTE: TRENCH ℄ SEPARATION IS 3 METERS MINIMUM

TYPICAL TRENCH CROSS—SECTIONAL VIEW

500kV SINGLE-PHASE SF_6 GITL

RIGID SYSTEM

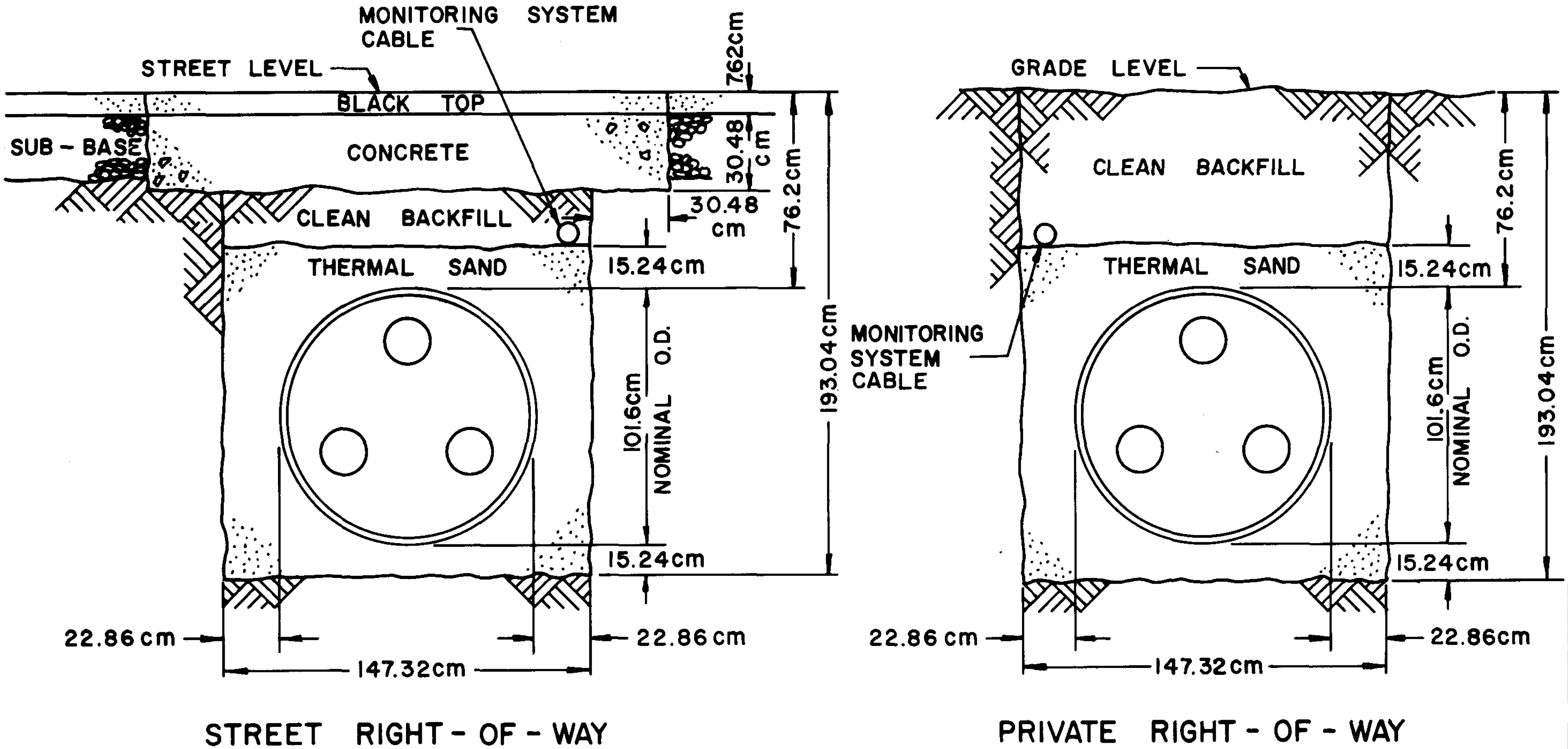
FIG. 10-2



NOTE: TRENCH ℄ SEPARATION IS 3 METERS MINIMUM

TYPICAL TRENCH CROSS-SECTIONAL VIEW
500 kV SINGLE-PHASE SF_6 GITL
FLEXIBLE SYSTEM

FIG. 10-3



NOTE : TRENCH ℄ SEPARATION IS 3 METERS MINIMUM

7.62 cm = 3 in	76.20 cm = 30 in
12.70 cm = 5 in	101.60 cm = 40 in
15.24 cm = 6 in	147.32 cm = 58 in
22.86 cm = 9 in	193.04 cm = 76 in
30.48 cm = 12 in	

TYPICAL TRENCH CROSS - SECTIONAL VIEW

500kV THREE PHASE SF_6 GITL

RIGID SYSTEM

FIG. 10 - 4

Table 10-1

Cable System Cost

500 kV Single-Phase SF_6 GITL Rigid System

3 Lines

Item	Quantity	Material K$	Labor K$	Total K$
I. Right of Way				
1. Street	29.4 ha. (72.7 ac.)	-	-	-
2. Private	294 ha. (720 ac.)	12,372		12,372
II. Clearing & Access Roads	294 ha. (720 ac.)	36	756	792
III. Enclosure*66.8 cm (26.3 in.) OD				
1. Street	30 km (18 mi.)	62,000	9,756	71,756
2. Private Right of Way	300 km (180 mi.)	649,500	47,125	696,625
IV. Excavation & Backfill (3ϕ)				
1. Street	30 km (18 mi.)	6,111	30,156	36,267
2. Private Right of Way	300 km (180 mi.)	8,476	134,622	143,098
V. SF_6 Gas	293×10^6 liters (10.3×10^6 cu. ft.)	52,315	5,813	58,128
VI. Terminations	6 sets	311	144	455
VII. Monitoring Systems		6,754	12,060	18,814
VIII. Engineering		-	5,515	5,515
IX. Maintenance (Capitalized)		5,500	12,750	18,250
X. Total		803,375	258,697	1,062,072

*Includes conductors

Table 10-2

Cable System Cost

500 kV Single-Phase SF_6 GITL Flexible System

5 Lines

Item	Quantity	Material K$	Labor K$	Total K$
I. Right of Way				
1. Street	47.1 ha. (116.4 ac.)	-	-	-
2. Private	471 ha. (1164 ac.)	19,640	-	19,640
II. Clearing & Access Roads	471 ha. (1164 ac.)	36	1,200	1,236
III. Enclosure*55.1 cm (21.7 in.) OD				
1. Street	48.2 km (30 mi.)	48,032	7,426	55,458
2. Private Right of Way	482 km (300 mi.)	474,668	36,227	510,895
IV. Excavation & Backfill (3ϕ)				
1. Street	48.2 km (30 mi.)	11,130	50,536	61,666
2. Private Right of Way	482 km (300 mi.)	13,991	202,670	216,661
V. SF_6 Gas	342.7×10^6 liters (12.1×10^6 cu. ft.)	61,085	6,787	67,872
VI. Terminations	10 sets	520	240	760
VII. Monitoring		11,256	20,100	31,356
VIII. Engineering Outside Plant		-	7,525	7,525
IX. Maintenance (Capitalized)		-	30,370	30,370
X. Total		640,358	363,081	1,003,439

*Includes conductors

Table 10-3

Cable System Cost

500 kV Three-Phase SF_6 GITL Rigid System

5 Lines

Item	Quantity	Material K$	Labor K$	Total K$
I. Right of Way				
1. Street	17.6 ha. (43.6 ac.)	-	-	-
2. Private	176 ha. (436 ac.)	7,500	-	7,500
II. Clearing & Access Roads	176 ha. (436 ac.)	36	472	508
III. Enclosure*101.6 cm (40 in.) OD				
1. Street	48.3 km (30 mi.)	58,356	6,328	64,684
2. Private Right of Way	483 km (300 mi.)	606,960	38,635	645,595
IV. Excavation & Backfill				
1. Street	48.3 km (30 mi.)	4,068	23,575	27,643
2. Private Right of Way	483 km (300 mi.)	8,160	124,080	132,240
V. SF_6 Gas	467.3×10^6 liters (16.5×10^6 cu. ft.)	83,160	9,240	92,400
VI. Terminations	10 sets	520	240	760
VII. Monitoring Systems		3,726	6,600	10,326
VIII. Engineering		-	2,575	2,575
IX. Maintenance (Capitalized)		3,000	7,123	10,123
X. Total		775,486	218,868	994,354

*Includes conductors

Table 10-4
Losses
500 kV SF_6 GITL Cable Systems

	3φ/Pipe Rigid		1φ/Pipe Rigid		1φ/Pipe Flexible	
	Radial	Network	Radial	Network	Radial	Network
I Transmission						
Total Losses MW (1)	54.45	54.45	67.27	67.27	119.5	119.5
Total MW Hr per year (2)	325,797	325,797	388,805	388,805	670,598	670,598
Energy Cost per year K$ (3)	5,734	5,734	6,843	6,843	11,803	11,803
Capitalized Energy Cost K$ (4)	35,180	35,180	41,980	41,980	72,408	72,408
Demand Cost K$ (1 & 5)	25,047	25,047	30,946	30,946	54,970	54,970
Sub-Total K$	60,227	60,227	72,926	72,926	127,378	127,378
II Substations						
Transformer Losses MW (1)	84.6	84.6	84.6	84.6	84.6	84.6
Total MW Hr per year (2)	521,400	521,400	521,400	521,400	521,400	521,400
Energy Cost per year K$ (3)	9,177	9,177	9,177	9,177	9,177	9,177
Capitalized Energy Cost K$ (4)	56,298	56,298	56,298	56,298	56,298	56,298
Demand Cost K$ (1 & 5)	38,916	38,916	38,916	38,916	38,916	38,916
Sub-Total K$	95,214	95,214	95,214	95,214	95,214	95,214
III Series Compensation						
Total Losses MW (1)	None	1.65	None	1.92	None	1.72
Total MW Hr per year (2)		9,588		11,116		10,013
Energy Cost per year K$ (3)		169		196		176
Capitalized Energy Cost K$ (4)		1,037		1,200		1,080
Demand Cost K$ (1 & 5)		758		882		792
Sub-Total K$		1,795		2,082		1,872
IV Shunt Compensation						
Total Losses MW (1)	None	None	3.42	1.42	None	None
Total MW Hr per year (2)			13,780	4,713		
Energy Cost per year K$ (3)			243	83		
Capitalized Energy Cost K$ (4)			1,490	509		
Demand Cost K$ (1 & 5)			1,573	538		
Sub-Total			3,063	1,047		
V Total Capitalized Cost of Energy Loss K$	155,441	157,236	171,203	171,269	222,592	224,464

Notes

(1) Based on 10,000 MW load level losses.
(2) Based on 9,000 MW and 7,200 MW load levels for 6 months each.
(3) Cost of energy 1.76¢ per KWH.
(4) Capitalized Cost if based on 40 year life and 16.3% Carrying charge rate.
(5) Demand cost is based on $460 per KW required to install the power system capacity to supply the losses.

Table 10-5

Cost Summary

500 kV SF_6 GITL Cable Systems

	3 Phase Pipe Rigid		1 Phase Pipe Rigid		1 Phase Pipe Rigid	
Material and Installation*	Radial	Network	Radial	Network	Radial	Network
Cable System	994,354	994,354	1,062,072	1,062,072	1,003,439	1,003,439
Substation	127,501	127,501	153,396	153,396	127,501	127,501
Series Compensation	None	7,830	None	4,845	None	7,885
Shunt Compensation	None	None	12,060	9,989	None	None
Sub Total	1,121,855	1,129,685	1,227,531	1,230,302	1,130,940	1,138,825
Losses (Capitalized)						
Cable	60,227	60,227	72,926	72,926	127,378	127,378
Substation	95,214	95,214	95,214	95,214	95,214	95,214
Series Comeensation	None	1,795	None	2,082	None	1,872
Shunt Compensation	None	None	3,063	1,047	None	None
Sub Total	155,441	157,236	171,203	171,269	222,592	224,464
Grand Total	1,277,296	1,286,921	1,398,770	1,401,571	1,353,532	1,363,289
Adjusted Grand Total*	1,338,707	1,348,799	1,538,853	1,541,938	1,417,960	1,428,193

*Includes capitalized maintenance costs
**Based on Economic Analysis in Section 3

11. RESISTIVE CRYOGENIC CABLE SYSTEM

11.1 General

Resistive cryogenic cable systems utilize refrigeration plants to cool and circulate nitrogen through the cable pipe to remove the heat generated by the cable losses. The internal cross-section of the 500 kV resistive cryogenic cable is shown in Figure 6-6. The aluminum conductor at $65^{o}K$ has approximately one-seventh the resistance it would have at $298^{o}K$ ($25^{o}C$) and, therefore, is capable of very high ratings. A separate pipe returns the nitrogen to the refrigeration plant. The distance between the refrigeration plants is determined by the allowable temperature rise of the nitrogen. Four circuits with 9,700 kcmil aluminum conductors are required for the 10,000 MW transmission system and are shown schematically in Figure 11-1. The typical trench cross-section is shown in Figure 11.2.

11.2 Material and Installation Costs

The installation costs are listed in Table 11-1. These costs were developed from the general installation details given in Section 3.9 and the following.

- The material costs for the cable, cable enclosure, and return pipe were supplied by the contractor developing the system under EPRI/ERDA sponsorship.
- The minimum bending radius of the enclosure is 45.7 m (150 ft.) and smaller radius bends are factory assembled.

11.2 Material and Installation Costs (cont'd)

- The fiberglass reinforced plastic (FRP) pipes were joined by FRP couplings cemented to the line pipe.
- Manholes were used for the connection of the refrigeration feed lines. Splices were made in splice pits which were more economical than manholes due to the length of the splices, approximately 6.5 m (19.8 ft.).
- The nitrogen costs were based on a delivered price of $2.40 per 1000 cu. ft. at NTP. The nitrogen was assumed to be delivered at the refrigeration plants and the labor for installation is included in the refrigeration startup costs.
- The monitoring system costs are based on thermal switches every 164 m (500 ft.) which would activate an alarm at the nearest refrigeration plant. There also are thermocouples in a hand hole every 500 ft. The alarm cable is routed through the manholes to facilitate maintenance and testing.

11.3 Losses

The losses for the system are summarized in Table 11-2 and are based on the general conditions outlined in Section 6.2. The refrigeration losses are high because all the I^2R losses are removed by the refrigerator which has an efficiency of 7.8 Watts/Watt.

11. RESISTIVE CRYOGENIC CABLE SYSTEM (cont'd)

11.4 Cost Summary

The total installed cost for the complete Resistive Cryogenic Cable System for both the radial and network installations is given in Table 11-3. The capitalized cost of losses represents approximately 28% of the total installed cost.

11.5 System Evaluation

11.5.1 General. The system design was supplied by the EPRI/ERDA-sponsored contractor and the 9,700 kcmil conductor was selected by the contractor to minimize the number of circuits. However, no tests were made on the proposed system and there exists some question whether a conductor that large could be pulled into an FRP pipe. Increasing the number of lines would reduce the conductor size but would probably increase the overall cost.

11.5.2 Reliability. The basic concept of a resistive cryogenic cable system is similar to a force-cooled HPOPT cable system and appears to be technically sound. However, the long-term reliability of FRP pipe with foam insulation is unknown as are the long-term electrical characteristics of the cable insulation at low temperatures.

11.5.3 Installation. The installation of the FRP pipe should present no unusual problems. However, new testing techniques must be developed to insure the integrity of the joints.

11. RESISTIVE CRYOGENIC CABLE SYSTEM

11.5 System Evaluation (cont'd)

11.5.4 Future Developments. The cost summary in Table 11-3 shows the cost of refrigeration and refrigeration losses to be over 50% of the total cost of the system. In order to make resistive cryogenic cable systems economically competitive, the losses must be reduced or the refrigeration costs and efficiency greatly improved.

11.6 345 kV Resistive Cryogenic Cable - Rigid System

11.6.1 General. A 345 kV rigid system using vacuum for both the electrical and thermal insulation was considered for inclusion in the study; however, major technical problems made a detailed cost analysis impossible. Areas which require additional consideration are listed below.

- The slip-fit connector design appears inadequate to carry either the continuous current or the fault current.
- Conductor longitudinal expansion and contraction require additional design considerations.
- Cleanliness during field construction would require extreme measures which would be costly.
- Maintaining vacuum quality over extended cable operations would be difficult.

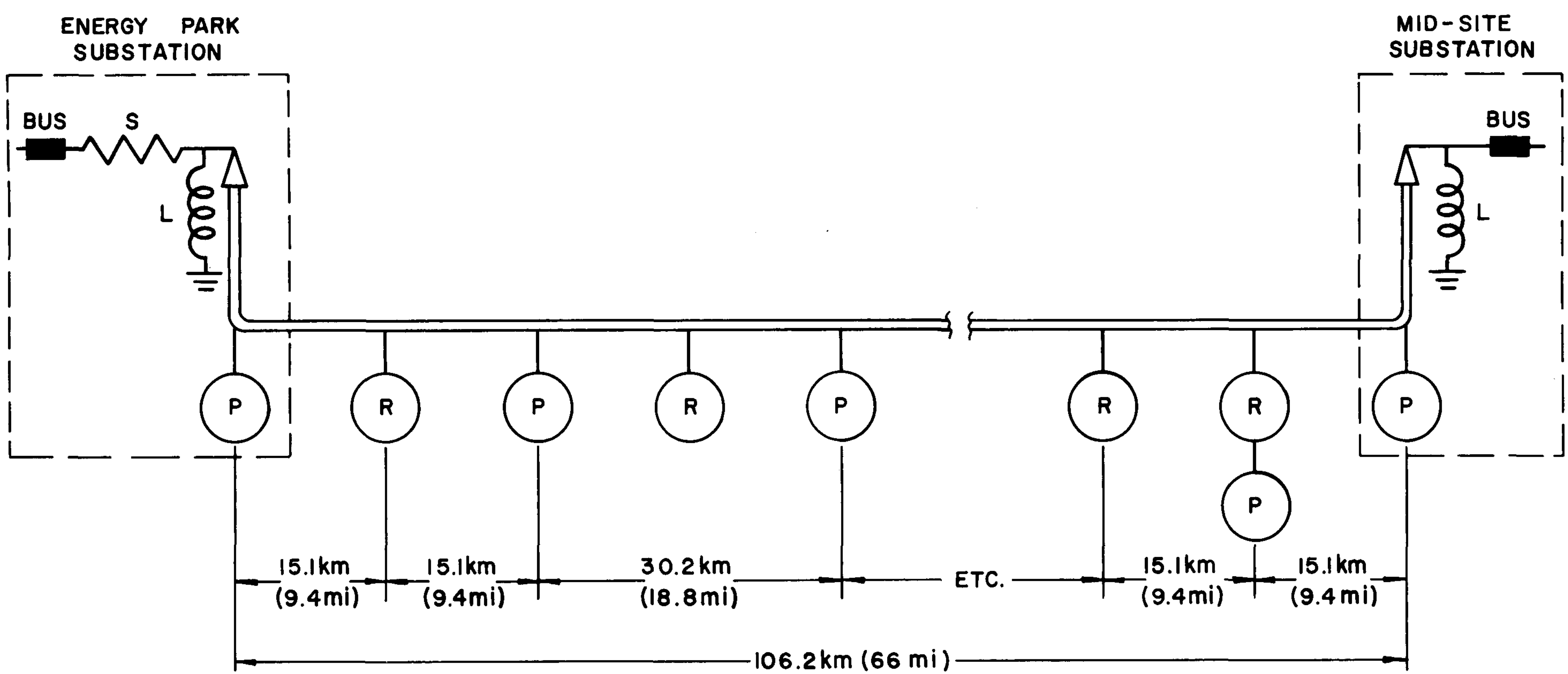
11. RESISTIVE CRYOGENIC CABLE SYSTEM

11.6 345 kV Resistive Cryogenic Cable - Rigid System

11.6.1 General (cont'd)

- BIL of the cable has not been established.
- Vacuum insulation requires more stringent preparation and testing prior to operation than other cable systems.

11.6.2 Evaluation. The design received from the EPRI/ERDA contractor developing this system proposed a three-circuit 345 kV design with a 27,000 kcmil conductor (see Figure 6-7). The conductor losses would be 1.4 times the losses of the 500 kV resistive cryogenic cable studied in this chapter. The high value of conductor losses coupled with other losses such as heat in-leak are a strong indication that the system would be uneconomical regardless of the technical problems discussed previously.



LEGEND

L = SHUNT COMPENSATION UNIT (1348 MVAR/LINE/UNIT)

P = LN_2 PUMPING STATION

R = REFRIGERATION STATION

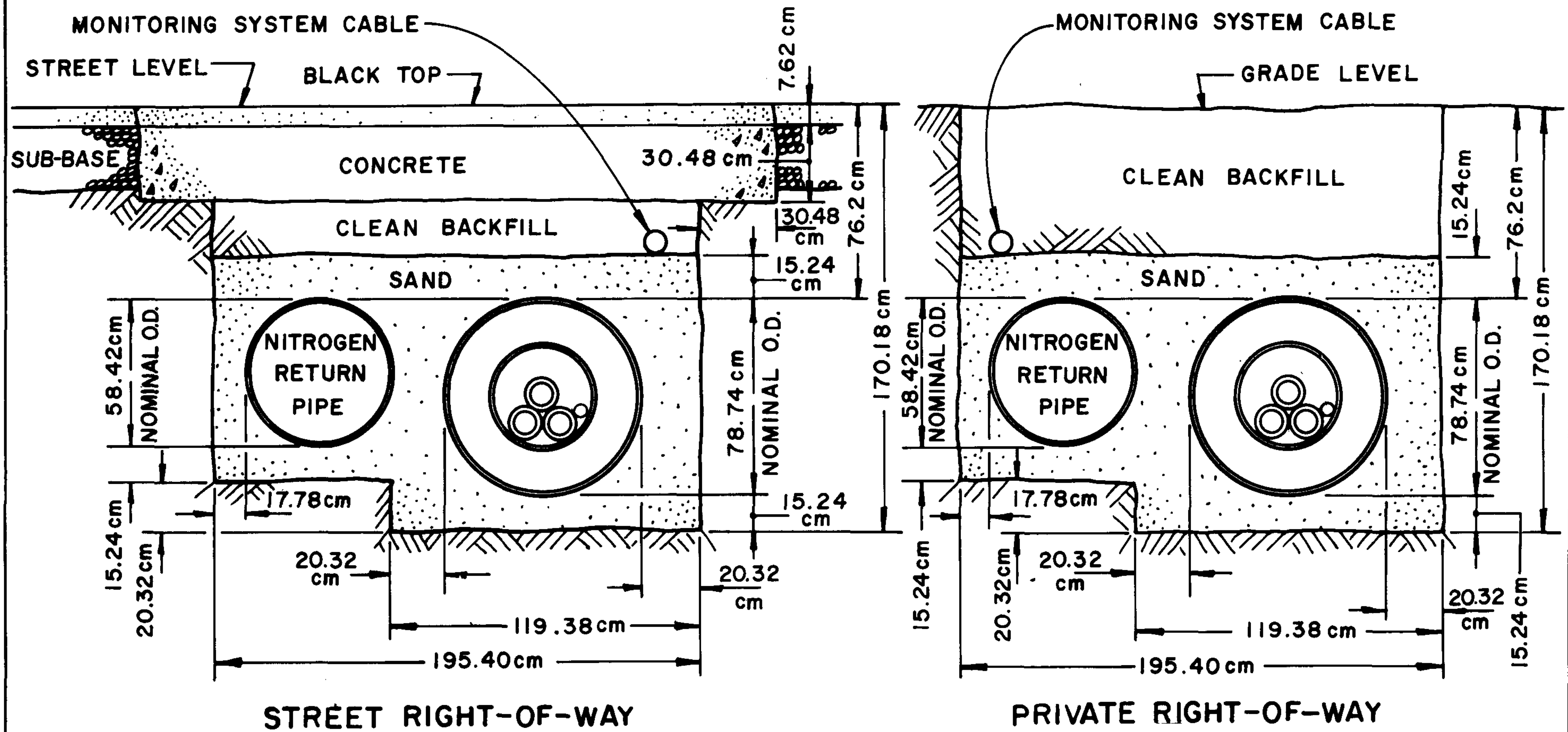
S = SERIES COMPENSATION UNIT:
FOR RADIAL SYSTEM, S=0
FOR NETWORK SYSTEM, S=-4 OHMS/LINE - (CAPACITIVE)

SYSTEM SCHEMATIC

500kV RESISTIVE CRYOGENIC CABLE

4 LINES

FIG. II-1



7.62 cm = 3 in	76.20 cm = 30 in
15.24 cm = 6 in	78.74 cm = 31 in
17.78 cm = 7 in	119.38 cm = 47 in
20.32 cm = 8 in	170.18 cm = 67 in
30.48 cm = 12 in	195.40 cm = 77 in
58.42 cm = 23 in	

NOTE: TRENCH ℄ SEPARATION IS 3 METERS MINIMUM.

TYPICAL TRENCH CROSS–SECTIONAL VIEW

500 kV RESISTIVE CRYOGENIC CABLE

FIG. 2

Table 11-1

Cable System Cost

500 kV Resistive Cryogenic Cable

4 Lines

Item	Quantity	Material K$	Labor K$	Total K$
I. Right of Way				
1. Street	16.9 ha. (41.8 ac.)	-	-	-
2. Private	169 ha. (418 ac.)	7,174	-	7,174
II. Clearing & Access Roads	169 ha. (418 ac.)	36	454	490
III. Enclosure, 76.7 cm (30.2 in.) OD				
1. Street	38.6 km (24 mi.)	26,513	4,770	31,283
2. Private right of way	386 km (240 mi.)	265,209	48,752	313,961
IV. Manholes - for ties to refrig. system	32	528	159	687
V. Excavation & Backfill				
1. Street	38.6 km (24 mi.)	3,405	21,138	24,543
2. Private right of way	386 km (240 mi.)	3,321	121,688	125,009
VI. Cable*, 3-1x9,700 kcmil Al.		357,350	16,104	373,454
VII. Nitrogen (labor in refrigeration)	43×10^6 liters (1.52×10^6 cu. ft.)	3,648	-	3,648
VIII. Terminations	8 sets	7,650	3,000	10,650
IX. Monitoring systems		2,077	1,577	3,654
X. Maintenance (capitalized)		2,030	6,070	8,100
XI. Engineering		-	1,560	1,560
XII. Total		678,941	225,272	904,213

*Includes cable, splicing and grounding system costs

Table 11-2
Losses
500 kV Resistive Cryogenic Cable System

		Radial	Network
I	Transmission and Refrigeration		
	Total Losses MW (1)	431.9	431.9
	Total MW Hr per year (2)	3,550,000	3,550,000
	Energy Cost per year K$ (3)	62,480	62,480
	Capitalized Energy Cost K$ (4)	383,312	383,312
	Demand Cost K$ (1 & 5)	198,674	198,674
	Sub Total K$	581,986	581,986
II	Substations		
	Transformer Losses MW (1)	84.6	84.6
	Total MW Hr per year (2)	521,400	521,400
	Energy Cost per year K$ (3)	9,177	9,177
	Capitalized Energy Cost K$ (4)	56,298	56,298
	Demand Cost K$ (1 & 5)	38,916	38,916
	Sub Total K$	95,214	95,214
III	Series Compensation		
	Total Losses MW (1)	None	.36
	Total MW Hr per year (2)		2,100
	Energy Cost per year K$ (3)		37
	Capitalized Energy Cost K$ (4)		227
	Demand Cost K$ (1 & 5)		160
	Sub Total K$		387
IV	Shunt Compensation		
	Total Loss MW (1)	32.4	32.4
	Total MW Hr per year (2)	283,824	283,824
	Energy Cost per year K$ (3)	4,995	4,995
	Capitalized Energy Cost K$ (4)	30,644	30,644
	Demand Cost K$ (1 & 5)	14,900	14,900
	Sub Total K$	45,544	45,544
V	Total Capitalized Cost of Energy Losses K$	722,744	723,131

Notes

(1) Based on 10,000 MW load level losses.
(2) Based on 9,000 MW and 7,200 MW load levels for 6 months each.
(3) Cost of energy 1.76¢ per KWH.
(4) Capitalized Cost if based on 40 year life and 16.3% Carrying charge rate.
(5) Demand cost is based on $460 per KW required to install the power system capacity to supply the losses.

Table 11-3
Cost Summary
500 kV Resistive Cryogenic Cable System

Material and Installation*	Radial K$	Network K$
Cable system	904,213	904,213
Refrigeration system	746,495	746,495
Substation	141,810	141,810
Series compensation	None	15,595
Shunt compensation	41,470	41,470
Sub-Total	1,833,988	1,849,583
Losses (Capitalized)		
Cable and refrigeration	581,986	581,986
Substation	95,214	95,214
Series compensation	None	387
Shunt compensation	45,544	45,544
Sub-Total	722,744	723,131
Grand Total	2,556,732	2,572,714
Adjusted Grand Total	2,694,461	2,711,308

* Includes capitalized maintenance costs.

12. SUPERCONDUCTING CABLE SYSTEMS

12.1 General

The three superconducting cable systems included in this study use different refrigeration, thermal insulation, and cable designs. Helium refrigeration, discussed in Chapter 7, is used in all three cable systems to maintain the conductor temperature in the $4.5^{\circ}K$ to $12^{\circ}K$ range. These systems are more complex than force-cooled cable installations due to the dependence on excellent thermal insulation to maintain acceptable losses. The thermal insulation minimizes refrigeration requirements and allows long line lengths between refrigeration plants. The enclosure thermal design for all three systems is composed of an inner-pipe thermally insulated from an outer-pipe. The thermal insulation is improved by placing the multi-layer thermal insulation under vacuum. The vacuum section for 230 kV AC and 230 kV AC rigid SC systems are within the 18.3 m (60 ft.) enclosure length. However, the 300 kV DC SC system is designed with long vacuum sections. The use of helium as a coolant and a vacuum type thermal insulation substantially increases the cost of the enclosure and the joining and testing procedures. Portable clean rooms are required for alignment, welding, and testing. The internal cross-sectional views of the three superconducting cables are illustrated by Figures 6-8, 6-9, and 6-10. Not shown by the cross-sections are thermally insulating spacers used to support the inner pipe inside the outer enclosure.

12.1.1 230 kV AC SC. Figure 12-1 is the schematic for the three-line 230 kV superconducting cable system. Similar to HPOPT cable, this is a synthetic laminate insulated cable and all three phases are pulled into the inner enclosure together.

12. SUPERCONDUCTING CABLE SYSTEMS

12.1 General (cont'd)

12.1.2 230 kV AC SC Rigid. Figure 12-2 is the schematic for the three-line 230 kV superconducting cable system. The cable is a spacer-type system with helium used as the dielectric. This system requires five enclosure welds, three strap welds, and six conductor welds for each 18.3m(60 ft.) enclosure length and requires a corresponding number of tests. This is significantly more than the other two superconducting cables which require only three welds per enclosure length. The SC conductor operates at a lower temperature and at a more confined temperature range than the other systems.

12.1.3 300 kV DC SC. Figure 12-3 is the schematic for the three-line 300 kV DC monopolar superconducting cable system. The cable is laminate insulated and is pulled into the enclosure. The inner diameter of the enclosure design supplied by the contractor is too small for the desired pulling lengths and must be modified for cable installation. There is only one cable per cryogenic envelope.

12.2 Material and Installation Costs

Material cost estimates were obtained from the EPRI/ERDA contractors. However, some adjustments were made to maintain the comparative costs among the three systems.

The typical trench cross-sectional views are illustrated by Figures 12-4, 12-5, and 12-6. The installation costs were developed from the general details presented in Chapter 3.

12.2 Material and Installation Costs (cont'd)

The installed costs for all material and labor for the three systems are given in Tables 12-1, 12-2, and 12-3.

12.3 Losses

System losses are summarized in Table 12-4 and are based on the general conditions outlined in Section 6.2.

12.4 Cost Summary

The total installed costs for both radial and network superconducting systems are given in Table 12-5. The capitalized cost of losses represents approximately 14.5%, 11.3%, and 21% for the 230 kV AC, 230 kV SC-R, and 300 kV SC-DC systems, respectively.

12.5 System Evaluation

12.5.1 General. Presently, no superconducting cable systems are commercially available.

12.5.2 Reliability. These systems are complex, involving many interdependent components making it difficult to predict reliability. However, it is clear that repair of a cable system fault may involve several months' outage of a line. Natural warmup of the cable would require as much as one month and cool-down would require about the same duration. Accurate fault location methods require development due to the high cost of system repair.

12.5 System Evaluation (cont'd)

12.5.3 Installation. The installation techniques for superconducting systems need to be developed. For example, the use of helium requires special attention to welding techniques and weld testing methods.

The 300 kV SC-DC system enclosure may present installation and maintenance problems due to the long vacuum lengths proposed. The thermal insulation vacuum system is suggested to be 304.8 m (1000 ft.) long, requiring seventeen enclosures to be sealed and vacuum pumped in the field.

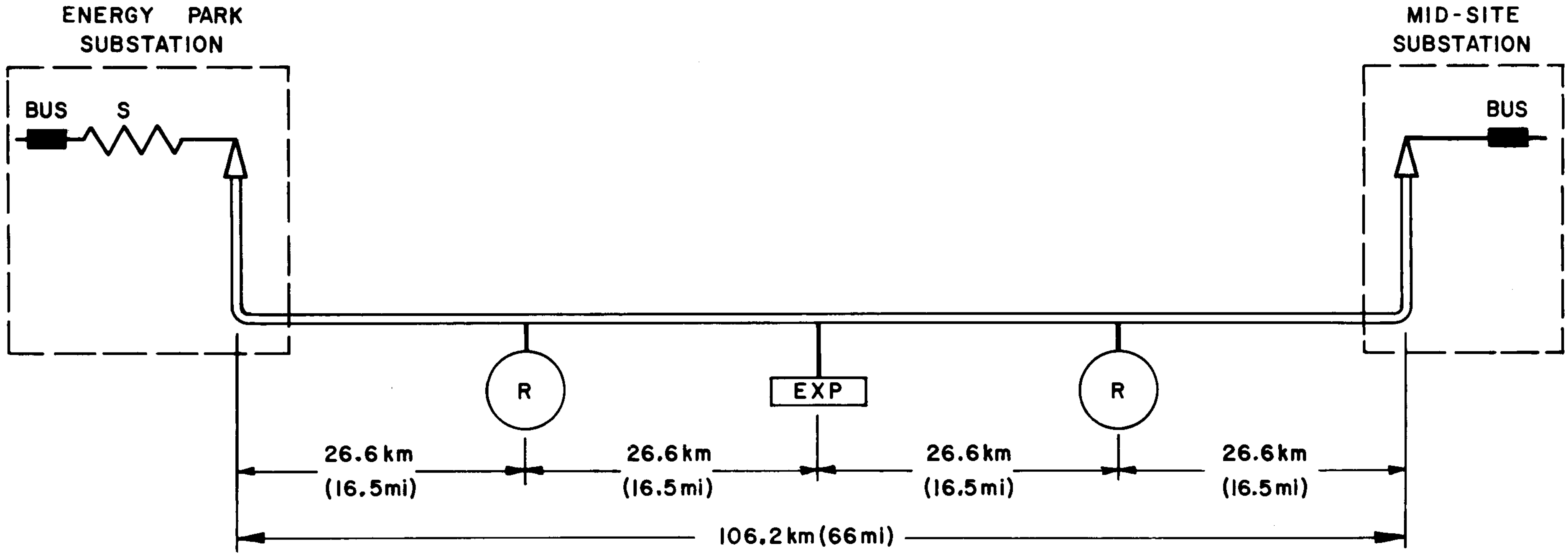
Considering the difficulties in obtaining and maintaining vacuum in such long sections, further consideration of this method appears to be necessary. The alternative technique of vacuum sealing each 18.29 m (60 ft.) enclosure length in the factory should be compared with the 1000-ft. vacuum sections to evaluate the economics of both techniques as well as to determine the feasibility of vacuum welding in the field. Techniques for repair and possible replacement of a damaged pipe must also be considered in evaluating the merits of the two designs.

12. SUPERCONDUCTING CABLE SYSTEMS

12.5 System Evaluation (cont'd)

12.5.4 Future Developments. Evaluation of the three superconducting cable systems shows a wide cost range. This evaluation assumes many improvements in order to attain the projected values used in the study. In addition, the ampacity requirements of the study are favorable to high ampacity systems. It would be advantageous if the SC systems could be improved so that they become competitive at lower ampacities, since most cable applications require ampacities well below the values used in this study.

Due to the SC enclosures' natural rigidity, the trench plan and profile require more costly design and construction criteria. Bends require longer radii and problems caused by intersecting utilities are costly to solve. Both the 230 kV AC and 300 kV DC SC systems installation assumed the use of a flexible enclosure section installed as needed to follow the trench installation. The 230 kV AC rigid system will require factory-made angled coupling.



LEGEND

R = REFRIGERATION STATION - (2 STATIONS)

EXP = EXPANDER STATION - (1 STATION)

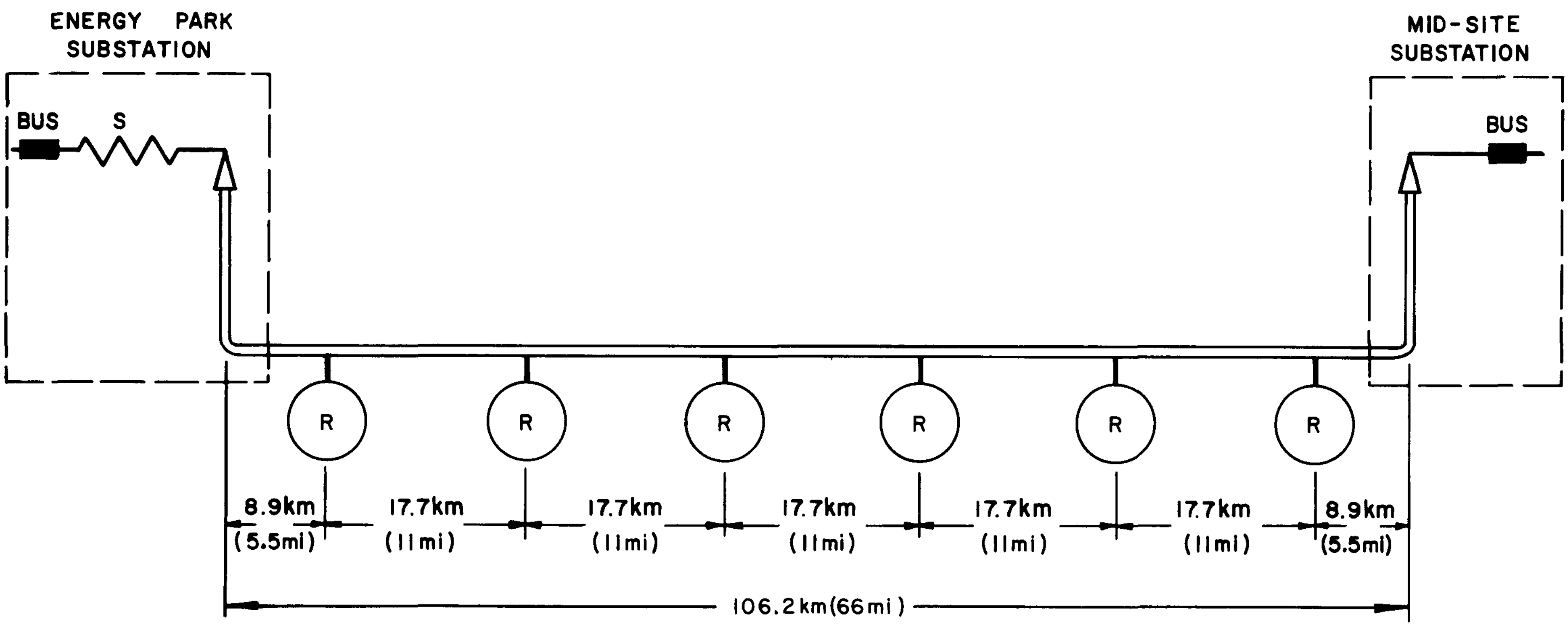
S = SERIES COMPENSATION UNIT:
FOR RADIAL SYSTEM, S = −0.29 OHMS/LINE - (CAPACITIVE)
FOR NETWORK SYSTEM, S = 0.16 OHMS/LINE - (INDUCTIVE)

SYSTEM SCHEMATIC

230kV SUPERCONDUCTING CABLE SYSTEM

3 LINES

FIG. 12-1



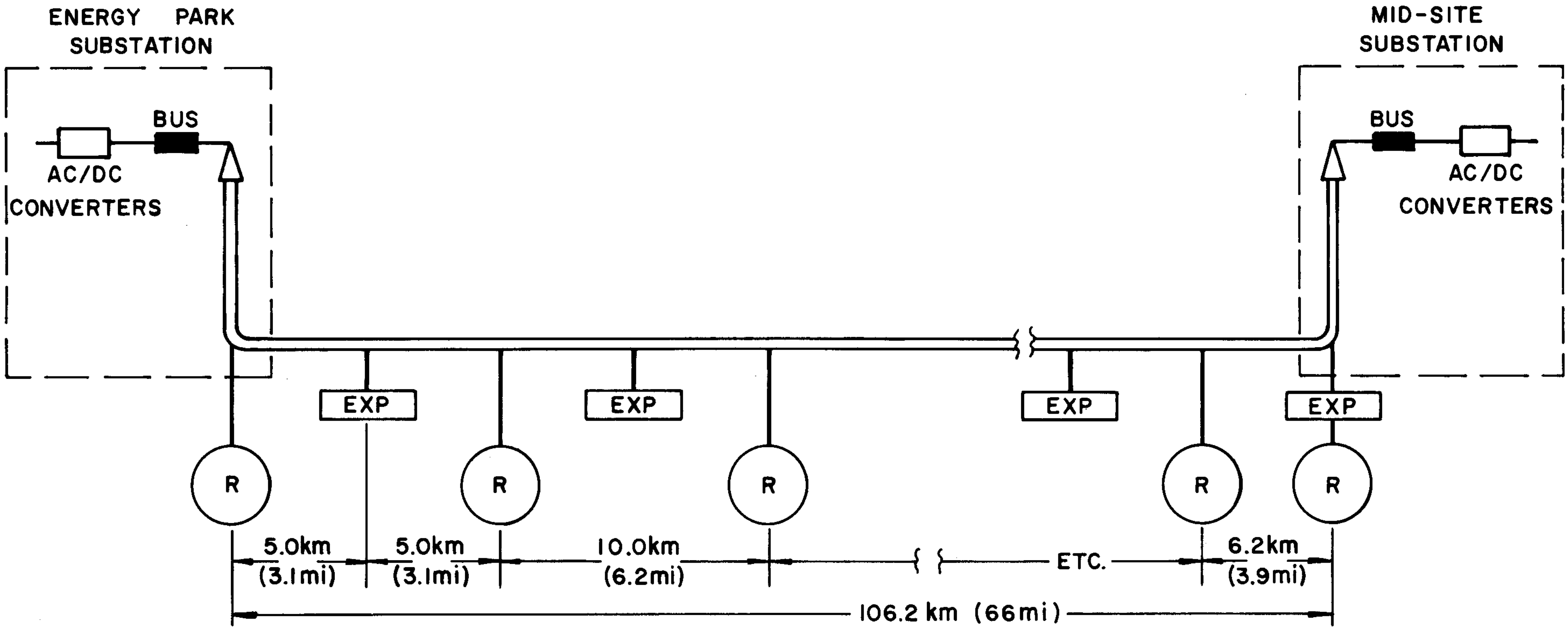
LEGEND

R = REFRIGERATION STATION-(6 STATIONS)

S = SERIES COMPENSATION UNIT:
FOR RADIAL SYSTEM, S = −10.92 OHMS/LINE-(CAPACITIVE)
FOR NETWORK SYSTEM, S = −10.48 OHMS/LINE-(CAPACITIVE)

SYSTEM SCHEMATIC
230kV SUPERCONDUCTING RIGID CABLE SYSTEM
3 LINES

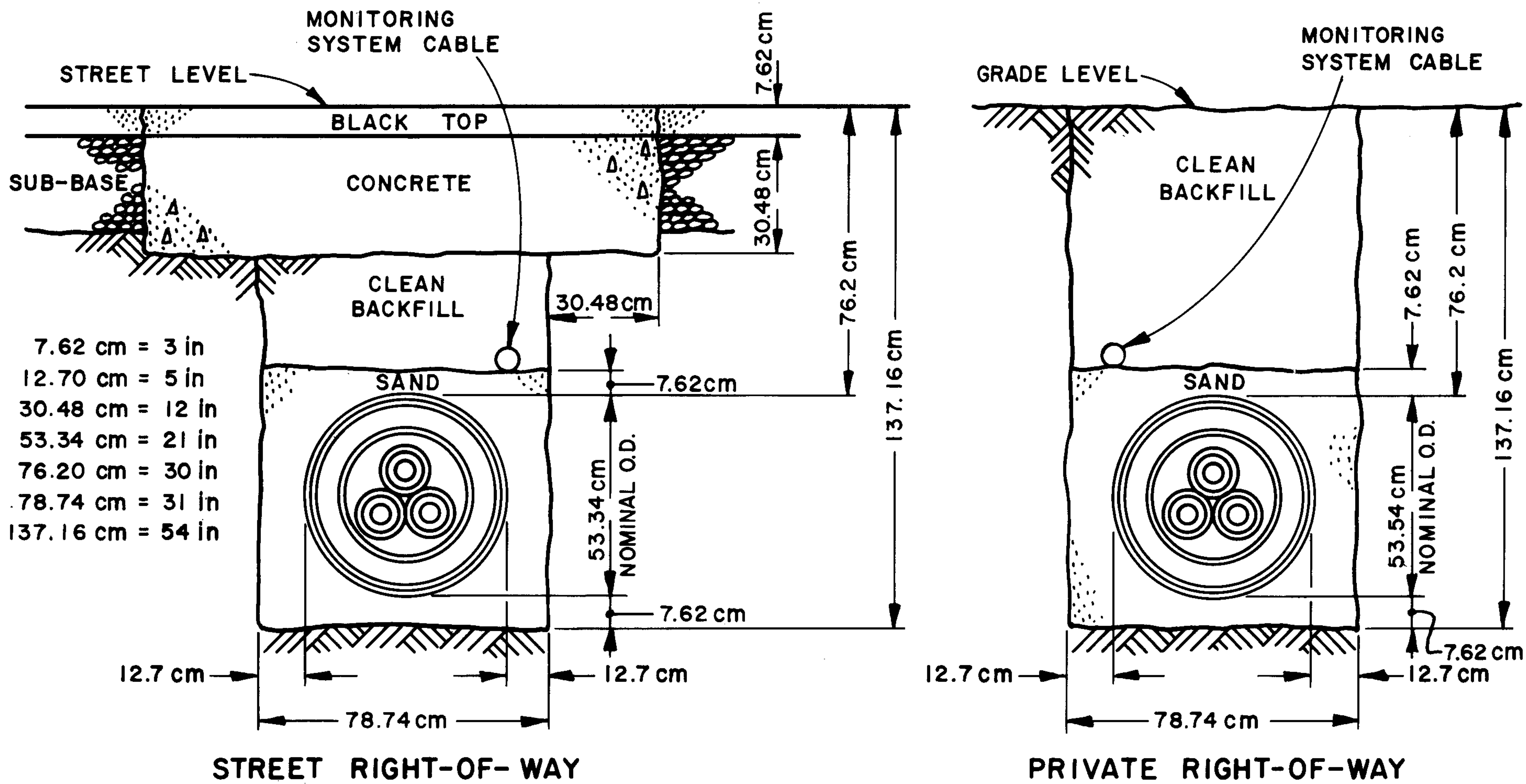
FIG. 12-2



LEGEND
R = REFRIGERATION STATION – (12 STATIONS)
EXP = EXPANDER STATION – (11 STATIONS)

SYSTEM SCHEMATIC
300kV DC SUPERCONDUCTING CABLE SYSTEM
3 LINES

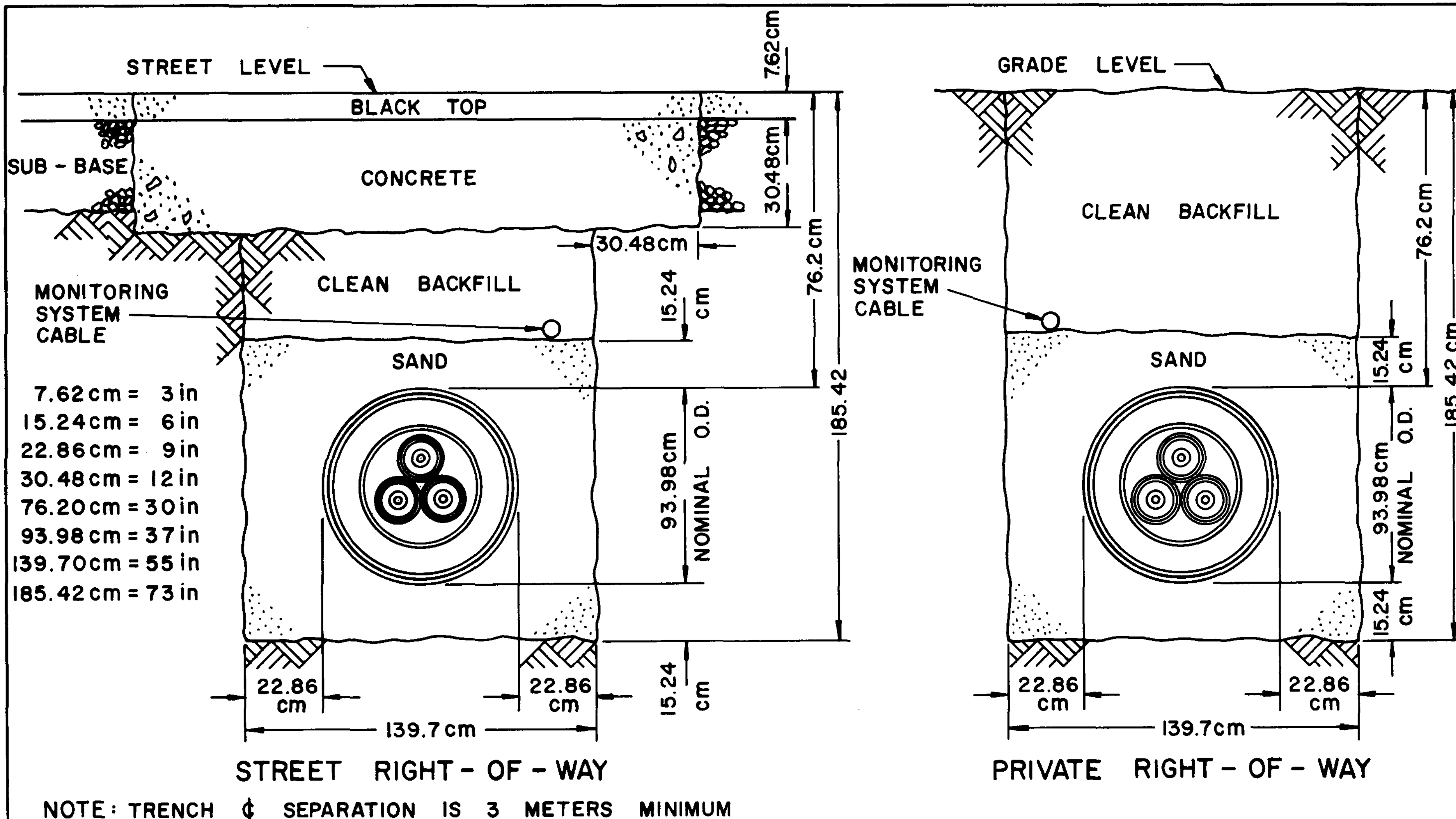
FIG. 12-3



NOTE: TRENCH ℄ SEPARATION IS 3 METERS MINIMUM

TYPICAL TRENCH CROSS-SECTIONAL VIEW
230 kV SUPERCONDUCTING CABLE

FIG. 12-4

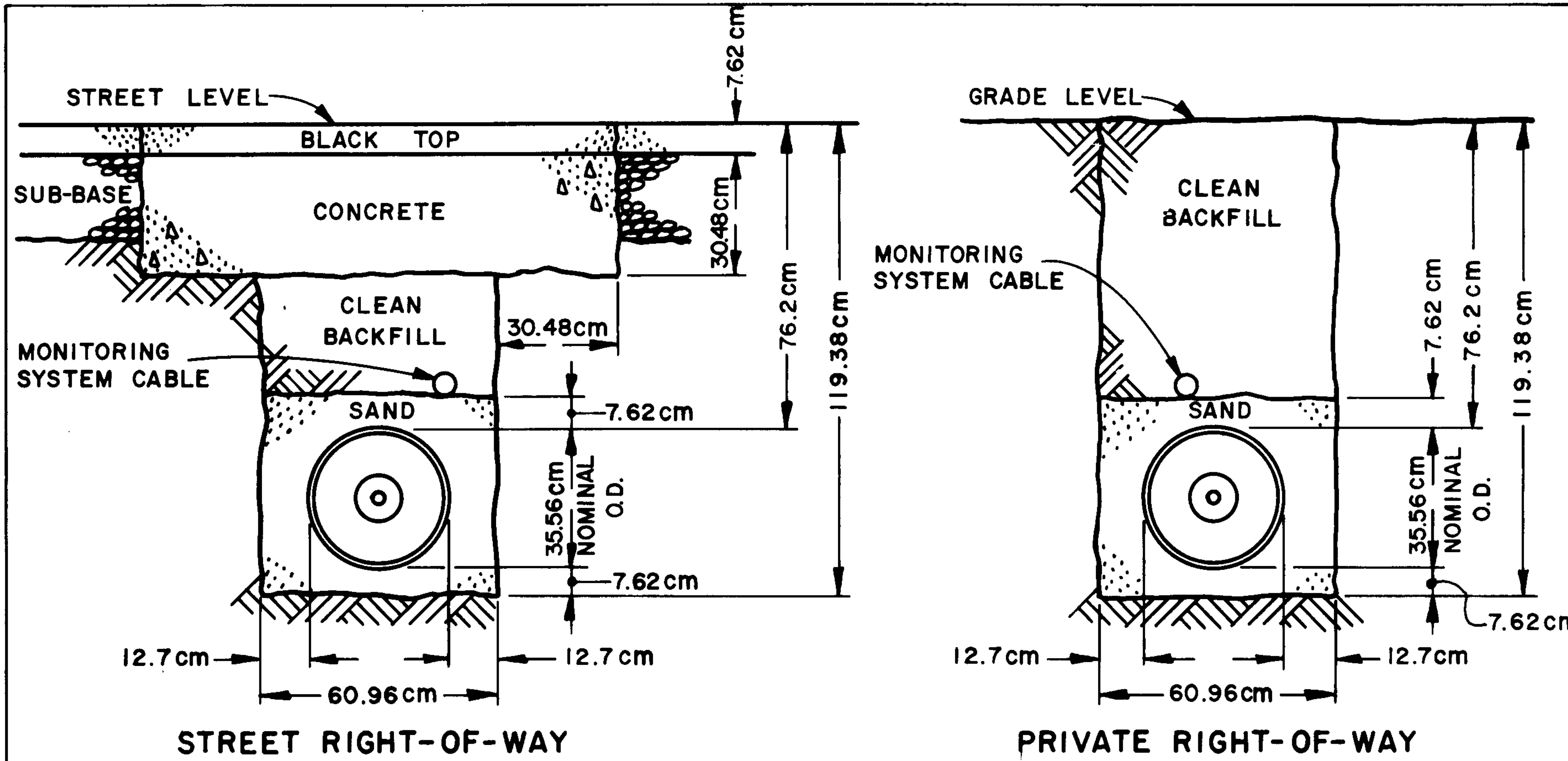


TYPICAL TRENCH CROSS - SECTIONAL VIEW

230kV SUPERCONDUCTING CABLE

RIGID SYSTEM

FIG. 12-5



7.62 cm = 3 in
12.70 cm = 5 in
30.48 cm = 12 in
35.56 cm = 14 in
60.96 cm = 24 in
76.20 cm = 30 in
119.38 cm = 47 in

NOTE: TRENCH ℄ SEPARATION IS 3 METERS MINIMUM

TYPICAL TRENCH CROSS-SECTIONAL VIEW
300 kV DC SUPERCONDUCTING CABLE

FIG. 12-6

Table 12-1

Cable System Cost

230 kV Superconducting Cable

3 Lines

Item	Quantity	Material K$	Labor K$	Total K$
I. Right of Way				
1. Street	11.8 ha. (29.1 ac.)	-	-	-
2. Private	118 ha. (291 ac.)	4,950	-	4,950
II. Clearing & Access Roads	118 ha. (291 ac.)	36	327	363
III. Enclosure, 51.3 cm. (20.2 in.) OD				
1. Street	29 km (18 mi.)	14,076	7,709	21,785
2. Private right of way	290 km (180 mi.)	140,208	68,589	208,797
IV. Manholes - stop joint and expander locations	9	75	23	98
V. Excavation & Backfill				
1. Street	29 km (18 mi.)	2,108	13,014	15,122
2. Private right of way	290 km (180 mi.)	2,652	69,313	71,965
VI. Cable*, 3-1XSC	319 km (198 mi.)	344,164	10,692	354,856
VII. Helium (labor in refrigeration)	9.6×10^6 liters (339×10^6 cu. ft.)	33,900	-	33,900
VIII. Terminations - 3∅ sets	6 sets	7,650	2,250	9,900
IX. Monitoring systems		1,860	1,680	3,540
X. Maintenance (Capitalized)		1,530	4,600	6,130
XI. Engineering		-	5,250	5,250
XII. Total		553,209	183,447	736,656

*Includes cable and splicing costs.

Table 12-2

Cable System Cost

230 kV Superconducting Cable, Rigid System

3 Lines

Item	Quantity	Material K$	Labor K$	Total K$
I. Right of way				
1. Street	11.8 ha. (29.1 ac.)	-	-	-
2. Private	118 ha. (291 ha.)	4,950	-	4,950
II. Clearing & Access Roads	118 ha. (291 ha.)	36	327	363
III. Enclosure*90.8 cm. (35.7 in.) OD				
1. Street	29 km (18 mi.)	60,735	13,192	73,927
2. Private right of way	290 km (180 mi.)	617,540	100,980	718,520
IV. Manholes - refrigeration system ties locations	12	66	20	86
V. Excavation & Backfill				
1. Street	29 km (18 mi.)	2,602	13,053	15,655
2. Private right of way	290 km (180 mi.)	2,049	85,850	87,899
VI. Helium (labor in refrigeration)	79.9×10^6 liters (2.82×10^6 cu. ft.)	282,000	-	282,000
VII. Terminations	6 sets	4,080	1,200	5,280
VIII. Monitoring systems		1,980	1,740	3,720
IX. Maintenance (Capitalized)		1,530	4,600	6,130
X. Engineering		-	5,100	5,100
XI. Total		977,568	226,062	1,203,630

*Includes conductor

Table 12-3

Cable System Cost

300 kV DC Superconducting Cable

3 Lines

Item	Quantity	Material K$	Labor K$	Total K$
I. Right of Way				
1. Street	11.8 ha. (29.1 ac.)	-	-	-
2. Private	118 ha. (291 ac.)	4,950	-	4,950
II. Clearing & Access Roads	118 ha. (291 ac.)	36	327	363
III. Enclosure, 33 cm (13 in.) OD				
1. Street	29 km (18 mi.)	9,948	7,039	16,987
2. Private right of way	290 km (180 mi.)	98,927	62,315	161,242
IV. Manholes	594	3,267	980	4,247
V. Excavation & Backfill				
1. Street	29 km (18 mi.)	2,020	10,365	12,385
2. Private right of way	290 km (180 mi.)	4,049	43,890	47,939
VI. Cable*, 1XSC	319 km (198 mi.)	89,575	5,841	95,416
VII. Helium (labor in refrigeration)	0.262×10^6 liters (9.24×10^6 cu. ft.)	924	-	924
VIII. Terminations-1 monopolar	6	5,100	1,500	6,600
IX. Monitoring Systems		1,425	890	2,315
X. Maintenance (Capitalized)		1,530	4,600	6,130
XI. Engineering		-	4,110	4,110
XII. Total		221,751	141,857	363,608

*Includes cable and splicing costs.

Table 12-4
Losses
Superconducting Cable Systems

	230 kV AC		Rigid 230 kV AC		300 kV DC	
	Radial	Network	Radial	Network	Radial	Network
I Transmission and Refrigeration						
Total Losses MW (1)	69.7	69.7	126.8	126.8	13.75	13.75
Total MW Hr per year (2)	610,537	610,537	1,111,118	1,111,118	120,494	120,494
Energy Cost per year K$ (3)	10,745	10,745	19,556	19,556	2,120	2,120
Capitalized Energy Cost K$ (4)	65,923	65,923	119,975	119,975	13,000	13,000
Demand Cost K$ (1 & 5)	32,062	32,062	58,328	58,328	6,325	6,325
Sub Total K$	97,985	97,985	178,303	178,303	19,325	19,325
II Substations						
Transformer Losses MW (1 & 6)	63.13	63.13	63.13	63.13	247.13	247.13
Total MW Hr. per year (2)	395,000	395,000	395,000	395,000	1,746,950	1,746,950
Energy Cost per year K$ (3)	6,968	6,968	6,968	6,968	30,746	30,746
Capitalized Energy Cost K$ (4)	42,750	42,750	42,750	42,750	188,626	188,626
Demand Cost K$ (1 & 5)	29,040	29,040	29,040	29,040	113,680	113,680
Sub Total K$	71,790	71,790	71,790	71,790	302,306	302,306
III Series Compensation						
Total Losses MW (1)	.164	None	6.2	5.9	None	None
Total MW Hr. per year (2)	955		36,040	34,585		
Energy Cost per year K$ (3)	17		634	609		
Capitalized Energy Cost K$ (4)	100		3,890	3,736		
Demand Cost K$ (1 & 5)	75		2,852	2,714		
Sub Total K$	175		6,742	6,450		
IV Total Capitalized Cost of Energy Losses K$	169,950	169,775	256,835	256,543	321,631	321,631

Notes

(1) Based on 10,000 MW load level losses not including start up.
(2) Based on 9000 MW and 7200 MW load levels for 6 months each.
(3) Cost of energy 1.76¢ per KWH.
(4) Capitalized cost if based on 40-year life and 16.3% carrying charge rate.
(5) Demand cost is based on $460 per KW required to install the power system capacity to supply the losses.
(6) The 300 HVDC losses include transformers, valves, filters, smoothing reactors and auxiliaries.

Table 12-5

Cost Summary

Superconducting Cable Systems

Material and Installation (1)	230 kV AC Radial K$	230 kV AC Network K$	Rigid 230 kV AC Radial K$	Rigid 230 kV AC Network K$	300 kV DC Radial K$	300 kV DC Network K$
Cable System	736,656	736,656	1,203,630	1,203,630	363,608	363,608
Substation	107,559	107,559	107,559	107,559	729,070(2)	729,070(2
Series Compensation	17,100	None	488,545	477,515	None	None
Refrigeration System	146,540	146,540	333,351	333,351	128,184	128,184
Sub Total	1,007,855	990,755	2,133,085	2,122,055	1,220,862	1,220,860
Losses (Capitalized)						
Cable and Refrigeration	97,985	97,985	178,303	178,303	19,325	19,325
Substation	71,790	71,790	71,790	71,790	302,306(2)	302,306(2
Series Compensation	175	None	6,742	6,450	None	None
Sub Total	169,950	169,775	256,835	256,543	321,631	321,631
Grand Total	1,177,805	1,160,530	2,389,920	2,378,598	1,542,493	1,542,493
Adjusted Grand Total (3)	1,294,881	1,275,851	2,628,303	2,615,849	1,695,831	1,695,831

(1) Includes capitalized maintenance costs

(2) Includes DC conversion equipment

(3) Based on Economic analysis in Section 3

13. AERIAL/UNDERGROUND SYSTEM

13.1 General

The 500 kV aerial/underground system schematic, Figure 13-1, specifies 9.66 km (6 mi.) of the system as cable. It is not practical to install 500 kV aerial lines on city streets and, therefore, this line section is specified to be underground cable. The basic line design parameters for the aerial portion are listed in Table 13-1, and the typical right-of-way cross-sectional view is shown in Figure 13-2.

A five-circuit system was selected based on economic consideration of construction costs versus compensation requirements and capitalized losses. Three circuits, with a three-conductor bundle of 2,312 kcmil ACSR, meet the rating criteria. However, three circuits require $253,000,000 for series compensation and have capitalized losses of $137,000,000. Increasing the number of circuits reduces the requirements for series compensation and reduces the losses. Five circuits, with a three-conductor bundle of 2,312 kcmil ACSR, results in the lowest system cost. A two-conductor bundle was also studied but increased capitalized losses of approximately $43,000,000, justifying the three-conductor bundle.

All 500 kV systems were considered for the underground portion. The three-phase SF_6, GITL, rigid system was selected based on the lowest installed cost for the required rating.

13.2 Material and Installation Costs

Installation costs for the aerial/underground system are listed in Table 13-2. The line design meets or exceeds the National Electrical Safety Code for a heavy ice and wind loading area. It is

13.2 Material and Installation Costs (cont'd)

interesting that the right-of-way costs represent 37% of the aerial line subtotal. The underground section costs are taken directly from Table 10-3 for city streets.

13.3 Losses

The total losses are shown in Table 13-3. The aerial losses represent a capitalized cost of approximately $277,000 per mile compared with $183,000 per mile for the underground portion. The total capitalized losses represent 27.6% of the system costs.

13.4 Cost Summary

The total installed cost for both the radial and network installations are given in Table 13-4. The substation and compensation costs are detailed in Chapter 5.

13.5 System Evaluation

13.5.1 General. For aerial lines, 500 kV is an accepted and mature design level in the United States. The three-phase GITL system is discussed in Chapter 10.

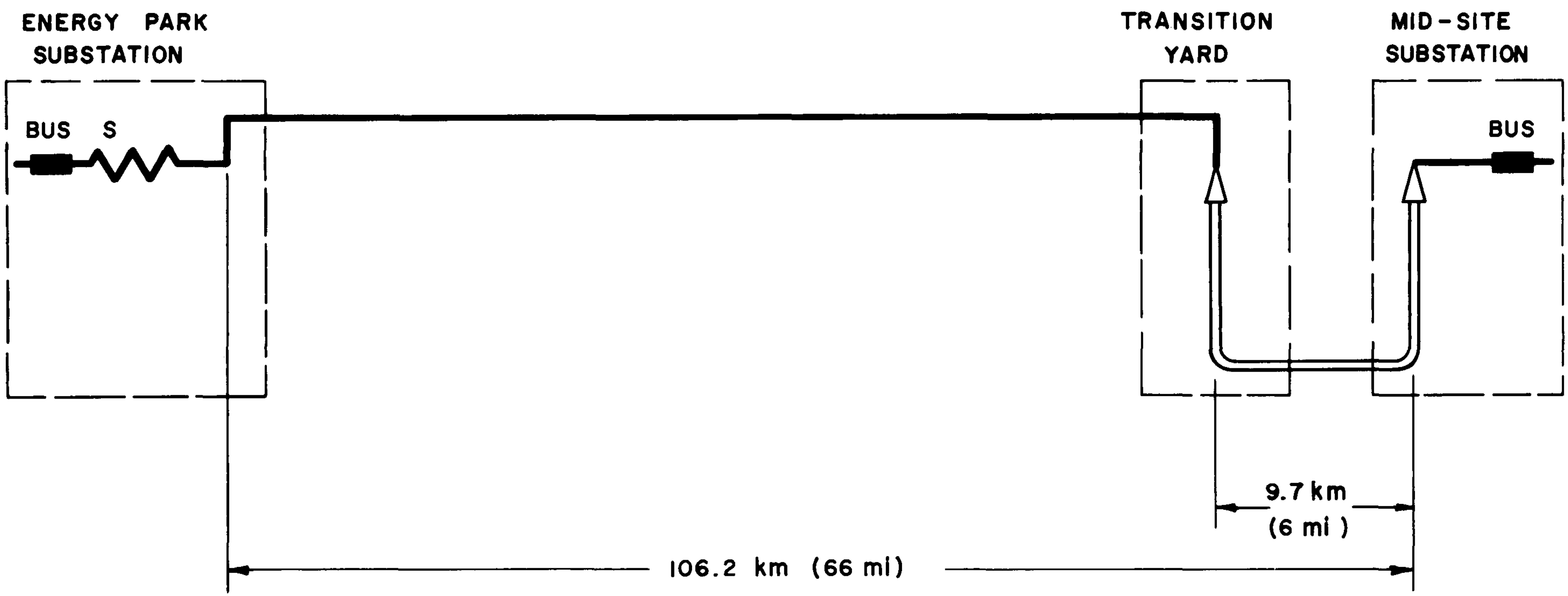
13.5.2 Reliability. The aerial line design has been proven reliable by many years of service. For simplicity, the study assumed the five lines would be on a single right-of-way. This would normally be unacceptable from a transmission reliability standpoint; therefore, two separate routes would be selected at little additional cost. The underground portion reliability is discussed in paragraph 10.5.2.

13. AERIAL/UNDERGROUND SYSTEM

13.5 System Evaluation (cont'd)

13.5.3 Installation. The aerial line construction techniques are well developed. The GITL system installation techniques are discussed in paragraph 10.5.3

13.5.4 Future Developments. The right-of-way cost is the most significant for the aerial portion of the line and development of more compact 500 kV lines would result in reduced cost and less environmental impact. The most likely use of high voltage underground systems in the near future will be in conjunction with an aerial line. The ability of an underground line to match the aerial line capacity, therefore, should be an important consideration in future research and development.



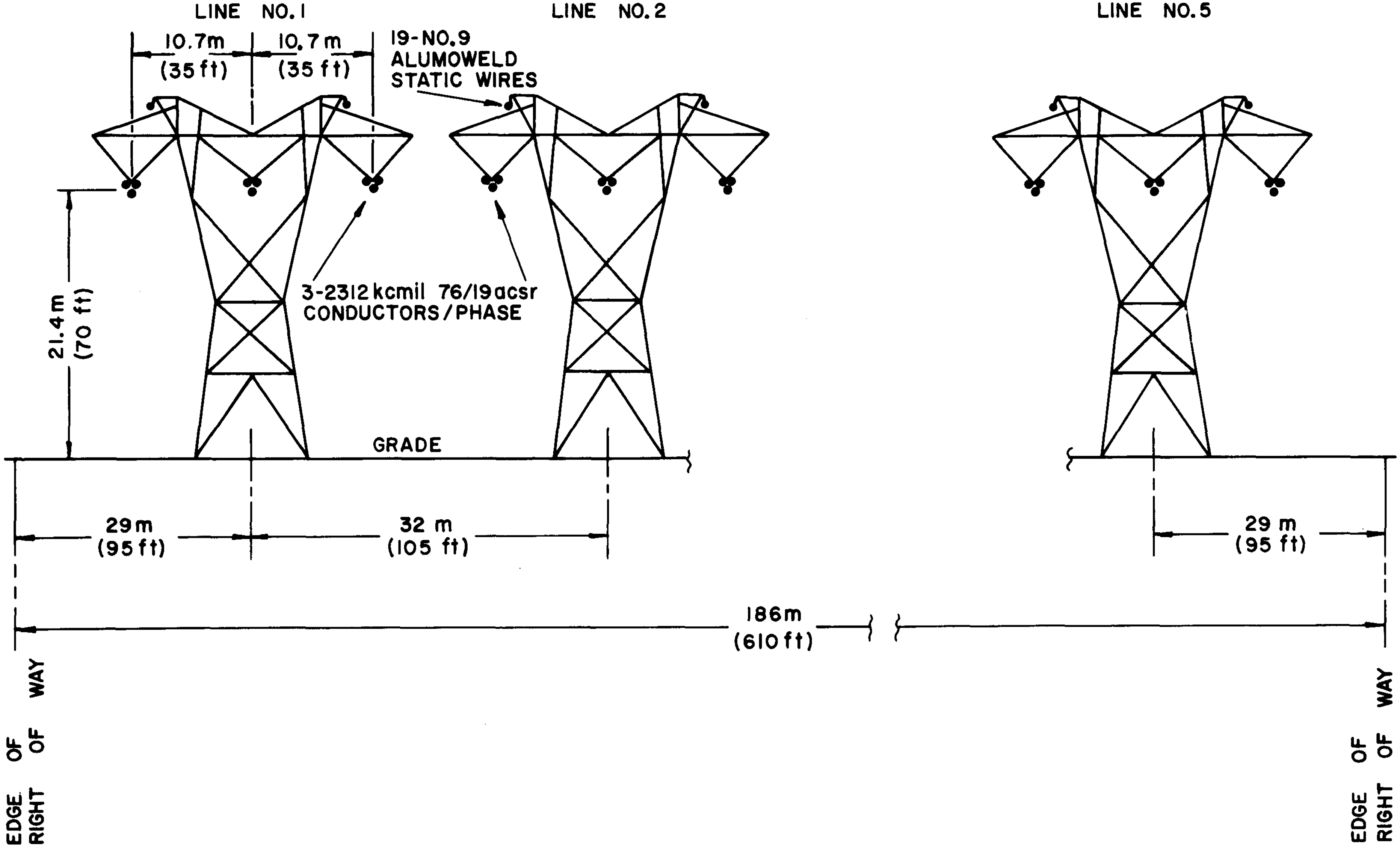
LEGEND

S = SERIES COMPENSATION UNIT:
FOR RADIAL SYSTEM, S = −7.5 OHMS / LINE −(CAPACITIVE)
FOR NETWORK SYSTEM, S = −20.2 OHMS / LINE −(CAPACITIVE)

NOTE: UNDERGROUND SECTION IS 500 KV THREE-PHASE SF_6, GITL, RIGID SYSTEM

SYSTEM SCHEMATIC
500 KV AERIAL-UNDERGROUND SYSTEM
5 LINES

FIG. 13-1



TYPICAL AERIAL RIGHT OF WAY CROSS-SECTIONAL VIEW

500kV LATTICE TYPE STRUCTURES

FIG. 13-2

Table 13-1

Design Data
500 kV Aerial System
Five Lines

Right of Way Width	186 m (610 ft.)
Conductor	3 x 2312 kcmil, 76/19 ACSR
Ground Wire	19 - #9 alumoweld
Phase Spacing	10.7 m (35 ft.)
Average Span Length	358 m (1175 ft.)
Minimum Clearance to Ground at 120°F	11.6 m (38 ft.)
BIL	1800 kV
Maximum Conductor Gradient	12.6 kV/cm
Ground Level Voltage Gradient	
Maximum	7.8 kV/m
Edge of ROW	2.1 kV/m
Audible Noise - Wet Conductor	
Maximum	33.5 db(A)
Edge of ROW	29.1 db(A)
Rating Amperes/Phase @ 125°C	6300
Loading-Amperes/Phase	
Normal	2309
1st Contingency	2886
2nd Contingency	2886
Tower Steel kg/km	45,660 (81 ton/mi.)
Tower Loading	NESC Heavy
Positive Sequence Impedance	
Resistive ohms/phase/km	.0099 (0.016 ohms/phase/mi.)
Reactive ohms/phase/km	.337 (.543 ohms/phase/mi.)
Zero Sequency Impedance	
Resistive ohms/phase/km	0.288 (0.463 ohms/phase/mi.)
Reactive ohms/phase/km	0.926 (1.490 ohms/phase/mi.)

Table 13-2

System Cost

500 kV Aerial-Underground System

5 Lines

Item	Quantity	Material K$	Labor K$	Total K$
I Aerial Section (1)	483 km (300 mi)			
1. Right of Way	1825 ha (4509 ac)	77,350	-	77,350
2. Clearing & Access Roads	1825 ha (4509 ac)	80	4,500	4,580
3. Foundations	1350	7,500	7,500	15,000
4. Towers	1350	21,870	19,440	41,310
5. Conductors and Devices (3 phase)	483 km (300 mi)	37,500	10,500	48,000
6. Engineering		-	7,500	7,500
7. Maintenacce (Capitalized)		2,030	13,300	15,330
8. Sub Total		146,330	62,740	209,070
II Underground Section (2)	48.3 km (30 mi)			
9. Sub Total		71,115	32,485	103,600
III Total		217,445	95,225	312,670

(1) Based on single circuit tower construction using 3-2313 kcmil (76/19) ACSR conductors.

(2) Based on three phase SF_6, GITL, rigid system.

Table 13-3
Losses
500 kv Aerial-Underground System

		Radial	Network
I	Transmission - Aerial		
	Total Losses MW (1)	77.16	77.16
	Total MW Hr per year (2)	440,190	440,190
	Energy Cost per year K$ (3)	7,750	7,750
	Capitalized Energy Cost K$ (4)	47,550	47,550
	Demand Cost K$ (1 & 5)	35,490	35,490
	Sub-Total	83,040	83,040
II	Transmission - Underground		
	Total Losses MW (1)	4.95	4.95
	Total MW Hr per year (2)	29,618	29,618
	Energy Cost per year K$ (3)	521	521
	Capitalized Energy Cost K$ (4)	3,200	3,200
	Demand Cost K$ (1 & 5)	2,280	2,280
	Sub-Total	5,480	5,480
III	Substations		
	Transformer Losses MW (1)	84.6	84.6
	Total MW Hr per year (2)	521,400	521,400
	Energy Cost per year (3)	9,177	9,177
	Capitalized Energy Cost K$ (4)	56,298	56,298
	Demand Cost K$ (1 & 5)	38,916	38,916
	Sub-Total	95,214	95,214
IV	Series Compensation		
	Total Losses MW (1)	.54	1.45
	Total MW Hr per year (2)	3,140	8,140
	Energy Cost per year K$ (3)	55	150
	Capitalized Energy Cost K$ (4)	340	920
	Demand Cost K$ (1 & 5)	250	670
	Sub-Total	590	1,590
V	Total Capitalized Cost of Energy Losses K$	184,324	185,324

Notes

(1) Based on 10,000 MW load level losses.
(2) Based on 9,000 MW and 7,200 MW load levels for 6 months each.
(3) Cost of energy 1.76¢ per KWH.
(4) Capitalized Cost is based on 40 year life and 16.3% Carrying charge rate.
(5) Demand cost is based on $460 per KW required to install the power system capacity to supply the losses.

Table 13-4

Cost Summary

500 kV Aerial-Underground System

Material and Installation*	Radial K$	Network K$
Aerial system	209,070	209,070
Underground system**	103,600	103,600
Substation	127,500	127,500
Series compensation	16,290	38,540
Sub Total	456,460	478,710
Losses (Capitalized)		
Aerial	83,040	83,040
Underground**	5,480	5,480
Substation	95,214	95,214
Series compensation	590	1,590
Sub Total	184,324	185,324
Grand Total	640,784	664,034
Adjusted Grand Total	667,850	692,229

* Includes capitalized maintenance costs.

** Based on 5 circuit, three phase SF_6 GITL Rigid System, 30 circuit miles in streets.

APPENDIX I

Capital Penalties for Use of Two Line Systems

Introduction

Most systems, including the PJM Interconnection to which Philadelphia Electric Company belongs, are designed and operated so they can withstand any single contingency such as the loss of any single bus, generator, line, transformer, etc. In addition, after such a loss and system readjustment, the system must be able to withstand the next contingency. In a two line system for the 10,000 MW Energy Park the outage of one line would mean, after system readjustment, that the system would have to be prepared for the loss of the Energy Park generation. Depending on the ability of the PJM system, its interconnection ties and the neighboring systems to withstand such a large generation outage, the generation at Energy Park would have to be rapidly reduced and picked up by other equipment. In effect, this would be a forced outage for the generation that was reduced and would affect both energy costs and installed reserve requirements. This report examines these effects and converts them into equivalent capital penalties for a two line system. Such penalties would be a basis for justifying a third line or justifying other system reinforcements so that a larger capacity loss could be sustained.

Results and Conclusions

This analysis has calculated the increase in installed capacity and energy costs for a two line system as a function of line forced outate rates which are the true unknowns. The capital penalties could justify the cost of either a third line or of system reinforcements. Examination of the cable systems which used three lines in this research project showed that the

Results and Conclusions (cont'd)

cost per line was between about 250 to 400 million dollars depending on cable type. In the relationships developed in this analysis, these dollars would correspond to the penalties of two line systems with forced outage rates of five to seven days per year. Though the actual failure frequencies are not known, it is expected that failures in any of the three line systems would take weeks to repair. The uncertainty of outage rates for futuristic cable systems without operational experience resulted in the decision that a minimum of three lines should be used for an initial application such as Energy Park.

The results of this analysis are expressed tabularly in Table AI-1 for the combinations of considered variables. The results are also expressed graphically in Figures AI-1 through AI-5.

Figure AI-1 describes capital penalty on a 1976 cost basis as a function of line forced outage rate for the assumed base conditions including:

1. Capital cost of generation capacity is $250/MW. (peaking capacity)
2. The energy replacement cost for the energy park generation is $20/MWh and is capitalized on a 16% carrying charge rate.
3. The maximum acceptable capacity risk is 2500 MW.

Figure AI-2 shows the effect of varying assumed capacity cost.

Figure AI-3 shows the effect of varying energy replacement cost.

Figure AI-4 shows the effect of varying the maximum acceptable risk level.

Results and Conclusions (cont'd)

Figure AI-5 shows the breakeven points between accepting capital penalties for higher maximum acceptable risks or providing additional system reinforcements to sustain the higher risks without penalty.

Discussion

The discussion is divided into three parts. The first part discusses the concept of maximum acceptable risk. If a system and all its neighboring systems were able to accept a maximum risk equal to the whole Energy Park of 10,000 MW, there would be no significant penalty for a two line system and this whole analysis would be academic. We believe such acceptance to be unlikely. The second part of the discussion describes the techniques that were used to calculate the capital penalties associated with the higher generation reserves that are required for a two line system. The third part describes the calculations used to determine off-cost generation that was required to replace Energy Park generation for a two line system.

Maximum Acceptable Risk

Presently the maximum capacity risk in the PJM Interconnection is the loss of a 1050 MW generator. Immediately after such a generator failure, its capacity is picked up by other operating generation in proportion to their inertia. Philadelphia Electric Company's generation is less than 2% of the Interconnected System's total (includes all reliability regions except WSCC and ERCOT) and PJM's generation is less than 11% of the total. Almost all of a Philadelphia Electric Company generation outage is, therefore, picked up on its tie lines to the PJM Interconnection and almost 90% on PJM's tie lines to neighboring systems and ultimately to the interior of these systems and their ties to other

Maximum Acceptable Risk (cont'd)

neighbors. The increases in loading on all these circuits would be added to their precontingency flows and could cause overloads dependent on the magnitude of the outage. Such overloads could not only lead to circuit trippings but possibly to cascading outages. Potential capacity outages are not only the concern of the host system but of all their neighbors and these are constantly being examined in interregional load flow studies. A number of years ago a neighboring system to PJM installed a very large generator. Load flow studies showed that its outage would overload ties on the other side of the PJM Interconnection. This generator had to be derated in capacity until previously planned transmission reinforcements were completed.

The maximum acceptable capacity risk would be unique to location and other system conditions. The cost of additional transmission to raise such risk levels would also be unique and would require detailed examination of not only the Philadelphia Electric Company and the PJM Interconnection but all the neighboring systems. The configuration of the PJM Interconnection in this study is only representative of the period of time, mid-1990's, selected for the analysis and will most likely be considerably different when that period is actually reached. The representations of neighboring systems are mainly equivalents which cannot be analyzed in detail. It would be a considerable task to expand these neighboring systems so that specific transmission reinforcements could be estimated for various energy park generation contingencies.

Maximum Acceptable Risk (cont'd)

Recent load flow studies, in which the Philadelphia Electric Company participated, indicated that transmission from the Philadelphia area to the borders of the PJM Interconnection would cost at least $100 per kW of transmission capability. We believe a similar figure would apply to the reinforcements required by the neighboring systems of the PJM Interconnection. Accordingly, a cost of $200/kW was applied in calculating reinforcement costs above the maximum acceptable risk level of 2500 MW. Since the present maximum capacity outage in PJM is 1050 MW, it was considered that normal transmission reinforcement would raise this level to about 2500 MW in the mid-1990's. The differences between the 2500 MW maximum acceptable risk penalties and penalties for higher risk levels were the savings that could accrue for these higher levels of risk. These savings were then compared with the cost of transmission reinforcements to obtain the breakeven points as a function of line forced outage rates. This is plotted in Figure AI-5, which shows that unless line forced outage rates were higher than 15 days/year, system reinforcements could not be economically justified.

The penalties for acceptable risk levels of 9000 and 10,000 MW are approximately zero, leading to equal potential savings at these levels. The breakeven points for transmission reinforcements at these levels are, therefore, the same. This causes a saturation of the breakeven point as a function of acceptable risk and line forced outage rate.

Capacity Penalty

The effect of reducing Energy Park generation after a line forced outage, in order to bring the generation level down to the maximum acceptable risk, is similar to the forced outage of a like amount of generation. The generation curtailment for a line forced outage has a significant effect on system reserve requirement. This effect was

Discussion

Capacity Penalty (cont'd)

calculated by using the reliability computer program ordinarily used by the PJM Interconnection for determining its reserve requirements on a probability basis. The program's two area capability was used to model the bulk of the system in one area and Energy Park in the second area. The program has the capability of performing its functions with various tie sizes between the two areas. Though the program can represent a tie forced outage rate, it cannot go from one tie level to another because of this forced outage. This would have been the convenient way to represent generation curtailment because of a line forced outage. Instead, the risks in days per year for full line availability and for the various levels of maximum risk with the assumption these existed the whole year were weighted by line availability and line unavailability respectively and added to produce the desired risk in days per year.

The reciprocal of these results produced the normal risk expression of years per day. The complete compilation of risk levels calculated is shown in Table AI-2 The following illustrates the method of calculation.

From computer runs:

Reliability level for 10,000 MW tie is 10 years/day or 0.1 days/year.
Reliability level for 2,500 MW tie is 1.0932 years/day or 0.9147 days/year.

Discussion

Capacity Penalty (cont'd)

For a line forced outage rate of one day per year, the tie forced outage rate is .00546 per unit (explained more fully under Energy Penalty) and availability rate is 0.99454.

For a 2500 MW maximum acceptable risk and a line forced outage rate of one day per year, the system reliability level is:

Tie	Per unit of time	Days/Yr. Risk Contribution	Weighted Contribution of risk in Days/Year
10,000 MW	(0.99454)	0.1	0.099454
2,500 MW	(0.00546)	0.9147	0.004994
			0.104448

1/0.104448 = 9.5741 years/day Probability of loss of load

This level is relative to a ten years/day Probability Loss of Load (PLOL) with either a 10,000 MW acceptable risk or zero line forced outage rate. To make all schemes equivalent, the calculated risk level would have to be raised to ten years/day PLOL by the addition of generation capacity. A characteristic of the PLOL calculations is that in the area of concern, ten years/day PLOL, a linear relation exists between the $\log_e$ of PLOL and percent reserve requirement. From computer runs is was determined that:

$$\frac{\text{Log}_e\,(\text{PLOL})_1 - \text{Log}_e\,(\text{PLOL})_2}{\%\ \text{Reserve}_1 - \%\ \text{Reserve}_2} = 0.28369$$

Discussion

Capacity Penalty (cont'd)

This is equivalent to a change of PLOL by a factor of ten (i.e., from 10 years/day to 1 year/day) for an 8.1% change in reserve. This relationship was used to convert the substandard PLOL levels in Table 2 to ten years/day by increasing capacity requirements. Using the previous example of 2500 MW maximum acceptable risk and line forced outage rate of 1 day/year, the continued calculations are:

$$\frac{\text{Log}_e\ (10) - \text{Log}_e\ (9.5741)}{0.28369} = 0.1535\ \%\ \text{change in}\ \%\ \text{reserve requirements}$$

(0.001535) (83,000 MW*) = 127 MW increased reserve requirements

At an assumed capital cost of $250/kW for additional generation this represents

($250/kW) (127,000 kW) = $31,750,000 penalty

The additional MW of generation required to raise reliability levels to 10 years/day is shown in Table AI-3.

* Peak Load of model system

Energy Penalty

During a line outage, generation at Energy Park is assumed curtailed in order to lower the risk to the maximum acceptable risk level. This curtailed generation must be replaced at a cost equal to or higher than the current running rate of the Interconnection. The average cost of replacement power for Philadelphia Electric Company nuclear capacity in

Discussion

Energy Penalty (cont'd)

1975 was about \$20/MWh and replacement cost for base-loaded coal capacity was about \$10/MWh. A base penalty of \$20/MWh was assumed for all curtailed generation. However, variations of \$10/MWh and \$30/MWh were also considered.

The calculations considered the unavailabilities of generation equipment. In the summer and winter non-maintenance seasons, it was assumed, based on a 10% forced outage rate, that only nine units would be operating. The curtailment for a 2500 MW maximum acceptable risk would be: 9,000-2500 = 6500 MW. Similarly, during the fall and spring maintenance seasons, two units were assumed out for maintenance and the remaining units had only a 90% availability. The curtailment for a 2500 MW maximum acceptable risk level would be:

$$(10{,}000 - 2{,}000)\ (.9) - 2500 = 4700 \text{ MW}$$

Cable maintenance was assumed to be only one day per year per line and would be performed during the generator maintenance season. The penalty for the 2500 MW maximum acceptable risk level was calculated to be:

$$2(1 \text{ day/yr})\ (24 \text{ hr/day})\ (4700 \text{ MW}) = 225{,}600 \text{ MWh}$$

$$(\$20/\text{MWh})\ (225{,}600 \text{ MWh}) = \$4{,}512{,}000$$

$$\frac{(\$4{,}512{,}000)}{(.16 \text{ carrying charge})} = \$28{,}200{,}000 \text{ capitalized energy costs}$$

Except for the lowest line forced outage rates, the maintenance penalty has only a nominal effect.

Discussion

Energy Penalty (cont'd)

The assumed line forced outage rates were used to calculate the days per half year* in which generation curtailment would occur.

Probability of one item being available out of N items:

$$\text{Probability} = NP^{N-1}(1-P)$$

where P is forced outage rate

i.e., let forced outage rate = 1 day/year

(1 day/year) (24 hours/day) / 8760 hours/year = .00274 forced outage rate

$$\text{Probability} = 2\ (.00274)^{2-1}(1-.00274)$$

$$= .00546$$

$$(.00546)\left(\frac{365}{2}\text{ days/yr}\right) = 1.0 \text{ day per half year}$$

Line Forced Outage Rate days/year	Half Year Probability of One Line Operation - days
1	1.0
2	1.99
3	2.98
4	3.96
5	4.93
10	9.73
15	14.38
20	18.90
30	27.53

* Calculations were performed separately for summer-winter and spring-fall seasons due to different generation curtailments.

Discussion

Energy Penalty (cont'd)

Following through the calculations for a 2500 MW maximum risk level the energy penalties for a 1 day/year forced outage are:

(1.0 day)(24 hr/day)(6500 MW S/W curtailment)	=	156,000 MWh
(1.0 day)(24 hr/day)(4700 MW Sp/F curtailment)	=	112,800 MWh
(Maintenance penalty)	=	225,600 MWh
total curtailed energy park energy		494,400 MWh

(494,400 MWh)($20/MWh) = $9,888,000 penalty/year

$$\frac{(\$9,888,000)}{(.16 \text{ carrying charge})} = \$61,800,000 \text{ capitalized energy penalty}$$

This penalty was added to the capital penalty for increased generation reserves to obtain the total penalty in Table AI-1 and the figures.

i.e., 2500 MW maximum acceptable risk
$250/kW generation capital cost
$20/MWh energy replacement cost

$31,750,000 generation reserve penalty
$61,800,000 capitalized energy replacement penalty
$93,550,000 total penalty

TABLE AI-1

Line Forced Outage Rate (Days/Yr.)	Penalties - Capital plus Capitalized Energy Costs - Thousands of Dollars: $150/kW Generator Cost and $20/MWh Energy Replacement Cost	$250/kW Generator Cost, Energy Replacement Cost: $10/MWh	$250/kW Generator Cost, Energy Replacement Cost: $20/MWh	$250/kW Generator Cost, Energy Replacement Cost: $30/MWh	$350/kW Generator Cost and $20/MWh Energy Replacement Cost
Maximum Acceptable Risk = 2000 MW					
1	$ 90,300	$ 71,400	$ 105,300	$ 139,200	$ 120,300
2	147,831	125,019	177,031	229,050	206,231
3	204,319	176,881	247,019	317,150	389,719
4	259,538	227,069	315,138	403,206	370,738
5	313,188	375,069	380,999	486,706	448,588
10	569,269	496,906	690,569	884,225	811,869
15	805,606	692,256	971,006	1,249,763	1,136,406
20	1,026,988	868,219	1,229,688	1,591,163	1,432,388
30	1,433,000	1,176,400	1,695,800	2,215,200	1,958,600
Maximum Acceptable Risk = 2500 MW					
1	80,850	62,650	93,550	124,450	106,250
2	132,413	109,781	157,313	204,844	182,213
3	183,075	155,413	219,575	283,744	256,075
4	232,656	199,625	280,256	360,881	327,856
5	281,150	242,425	339,350	436,275	397,550
10	531,375	441,313	618,875	796,444	724,375
15	729,019	618,431	874,119	1,129,800	1,019,219
20	952,738	814,119	1,145,738	1,477,363	1,338,738
30	1,304,956	1,062,856	1,539,456	2,016,063	1,773,956

TABLE AI-1 (Cont.)

Line Forced Outage Rate (Days/Yr.)	Penalties - Capital plus Capitalized Energy Costs - Thousands of Dollars				
	$150/kW Generator Cost and $20/MWh Energy Replacement Cost	$250/kW Generator Cost			$350/kW Generator Cost and $20/MWh Energy Replacement Cost
		Energy Replacement Cost			
		$10/MWh	$20/MWh	$30/MWh	
Maximum Acceptable Risk = 3000 MW					
1	$ 71,850	$ 54,650	$ 82,550	$ 110,450	$ 93,250
2	117,594	95,550	138,594	181,644	159,594
3	162,738	135,444	193,638	251.831	224,538
4	207,125	174,438	247,625	320,813	288,125
5	250,456	212,031	300,056	388,088	349,656
10	459,288	388,719	550,188	711,656	641,088
15	654,375	547,863	780,475	1,012,095	906,575
20	838,588	693,519	995,288	1,297,063	1,151,988
30	1,178,719	952,306	1,386,119	1,819,925	1,593,519
Maximum Acceptable Risk = 4000 MW					
1	54,900	40,400	62,300	84,200	69,700
2	90,056	70,575	104,656	108,569	119,256
3	124,906	100,256	146,506	147,944	168,106
4	159,219	129,306	187,619	186,531	216,019
5	192,825	157,488	227,725	224,850	262,625
10	356,656	292,781	422,056	411,519	487,456
15	511,100	416,725	603,200	589,000	695,300
20	658,138	532,069	774,138	758,863	890,138
30	931,488	739,969	1,088,188	1,436,406	1,244,888

TABLE AI-1 (Cont.)

Line Forced Outage Rate (Days/Yr.)	Penalties - Capital plus Capitalized Energy Costs - Thousands of Dollars				
	$150/kW Generator Cost and $20/MWh Energy Replacement Cost	$250/kW Generator Cost Energy Replacement Cost			$350/kW Generator Cost and $20/MWh Energy Replacement Cost
		$10/MWh	$20/MWh	$30/MWh	
Maximum Acceptable Risk = 5000 MW					
1	$ 39,150	$ 28,150	$ 44,050	$ 59,950	$ 48,950
2	64,763	49,356	74,463	99,569	84,163
3	90,225	70,313	104,625	138,944	119,025
4	115,206	90,675	134,106	177,531	153,006
5	140,000	110,950	163,400	215,850	186,800
10	260,925	208,338	305,425	402,519	349,925
15	376,069	299,331	439,669	580,000	503,269
20	486,388	385,119	567,488	749,863	648,588
30	692,956	542,131	804,756	1,067,388	916,556
Maximum Acceptable Risk = 6000 MW					
1	24,300	17,400	27,300	37,200	30,300
2	41,275	31,138	47,275	63,413	53,275
3	58,100	44,625	67,000	89,375	75,900
4	74,794	58,050	86,594	115,144	98,394
5	91,219	71,156	105,819	140,475	120,419
10	171,950	135,140	200,050	264,950	228,150
15	249,288	195,694	289,888	384,081	330,488
20	323,788	253,419	376,088	498,763	428,388
30	464,175	360,538	537,575	714,619	610,975

TABLE AI-1 (Cont.)

Line Forced Outage Rate (Days/Yr.)	Penalties - Capital plus Capitalized Energy Costs - Thousands of Dollars: $150/kW Generator Cost and $20/MWh Energy Replacement Cost	$250/kW Generator Cost, Energy Replacement Cost: $10/MWh	$250/kW Generator Cost, Energy Replacement Cost: $20/MWh	$250/kW Generator Cost, Energy Replacement Cost: $30/MWh	$350/kW Generator Cost and $20/MWh Energy Replacement Cost
	Maximum Acceptable Risk = 8000 MW				
1	$ 4,050	$ 3,250	$ 4,750	$ 6,250	$ 5,450
2	8,069	6,488	9,469	12,456	10,869
3	12,088	9,719	14,188	18,663	16,288
4	16,081	12,938	18,881	24,819	21,681
5	19,888	15,894	23,288	30,688	26,688
10	39,238	31,344	45,938	60,538	52,638
15	57,988	46,319	67,888	89,463	77,788
20	76,200	60,850	90,200	117,550	102,200
30	110,638	88,044	129,338	170,638	148,038

TABLE AI-2

RELIABILITY IN YEARS/DAY P.L.O.L.

Maximum Acceptable Single Contingency Risk - MW	Line Forced Outage Rate in Days Per Year								
	1	2	3	4	5	10	15	20	30
2,000	9.500	9.049	8.642	8.269	7.934	6.605	5.682	5.002	4.073
2,500	9.574	9.184	8.828	8.498	8.197	6.972	6.090	5.171	4.486
3,000	9.640	9.306	8.997	8.708	8.442	7.329	6.499	5.854	4.922
4,000	9.750	9.513	9.289	9.075	8.875	7.998	7.299	6.727	5.853
5,000	9.834	9.675	9.521	9.373	9.231	8.588	8.045	7.579	6.824
6,000	9.898	9.798	9.701	9.606	9.514	9.085	8.704	8.363	7.781
8,000	9.976	9.953	9.929	9.905	9.883	9.772	9.666	9.566	9.380
10,000	10.000	10.000	10.000	10.000	10.000	10.000	10.000	10.000	10.000

TABLE AI-3

Required Increase in Generation Reserves
to Obtain 10 Years/Day P.L.O.L. - MW

Maximum Acceptable Single Contingency Risk - MW	Line Forced Outage Rate in Days Per Year 1	2	3	4	5	10	15	20	30
2,000	150	292	427	556	677	1213	1654	2027	2628
2,500	127	249	365	476	582	1055	1451	1930	2345
3,000	107	210	309	405	496	909	1261	1567	2074
4,000	74	146	216	284	349	654	921	1160	1567
5,000	49	97	144	189	234	445	636	811	1118
6,000	30	60	89	118	146	281	406	523	734
8,000	7	14	21	28	34	67	99	130	187
10,000	0	0	0	0	0	0	0	0	0

PENALTY IN CAPITAL AND CAPITALIZED ENERGY COSTS VERSUS LINE FORCED OUTAGE RATE

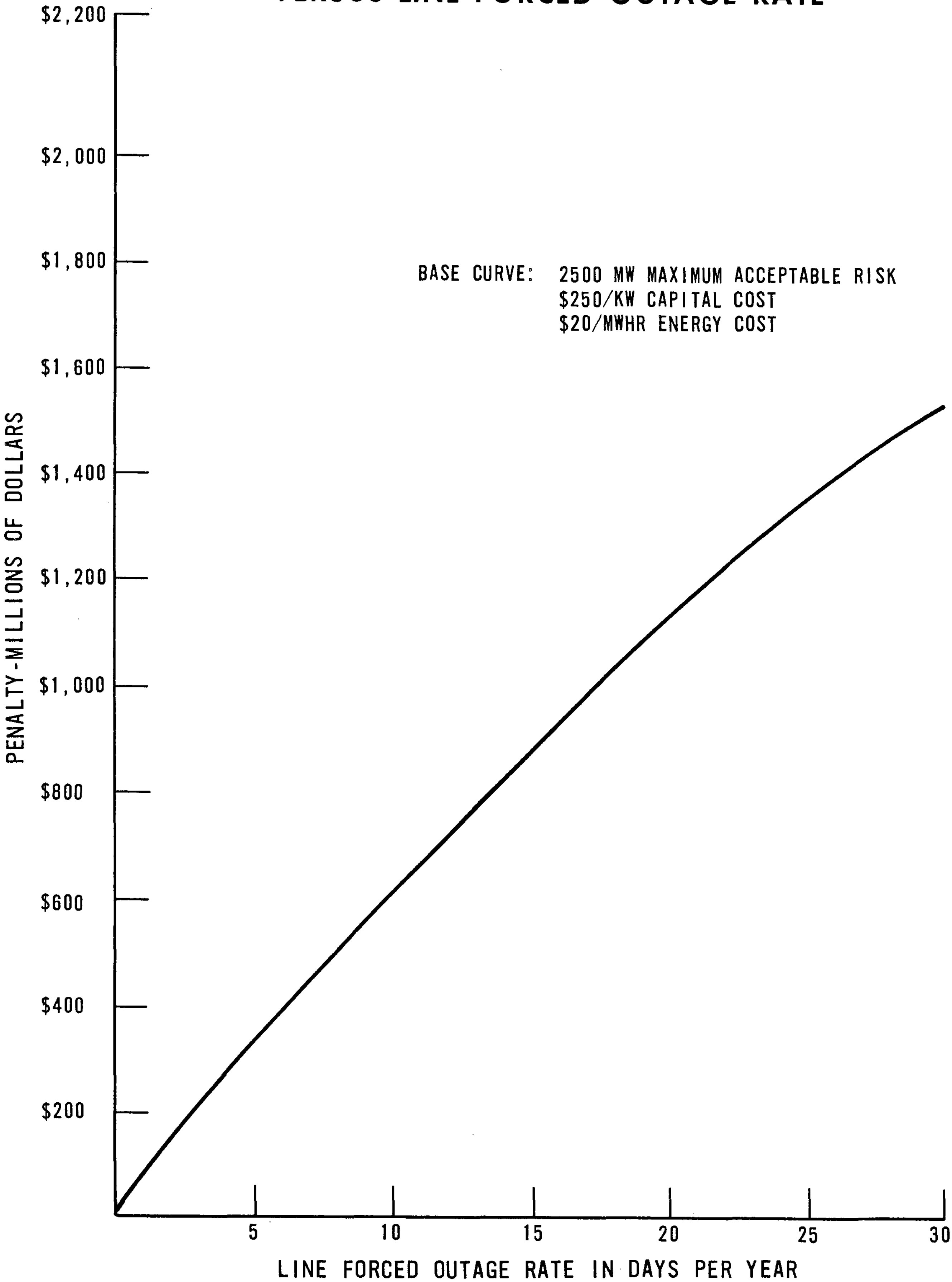


FIG. AI-1

PENALTY IN CAPITAL AND CAPITALIZED ENERGY COSTS VERSUS LINE FORCED OUTAGE RATE

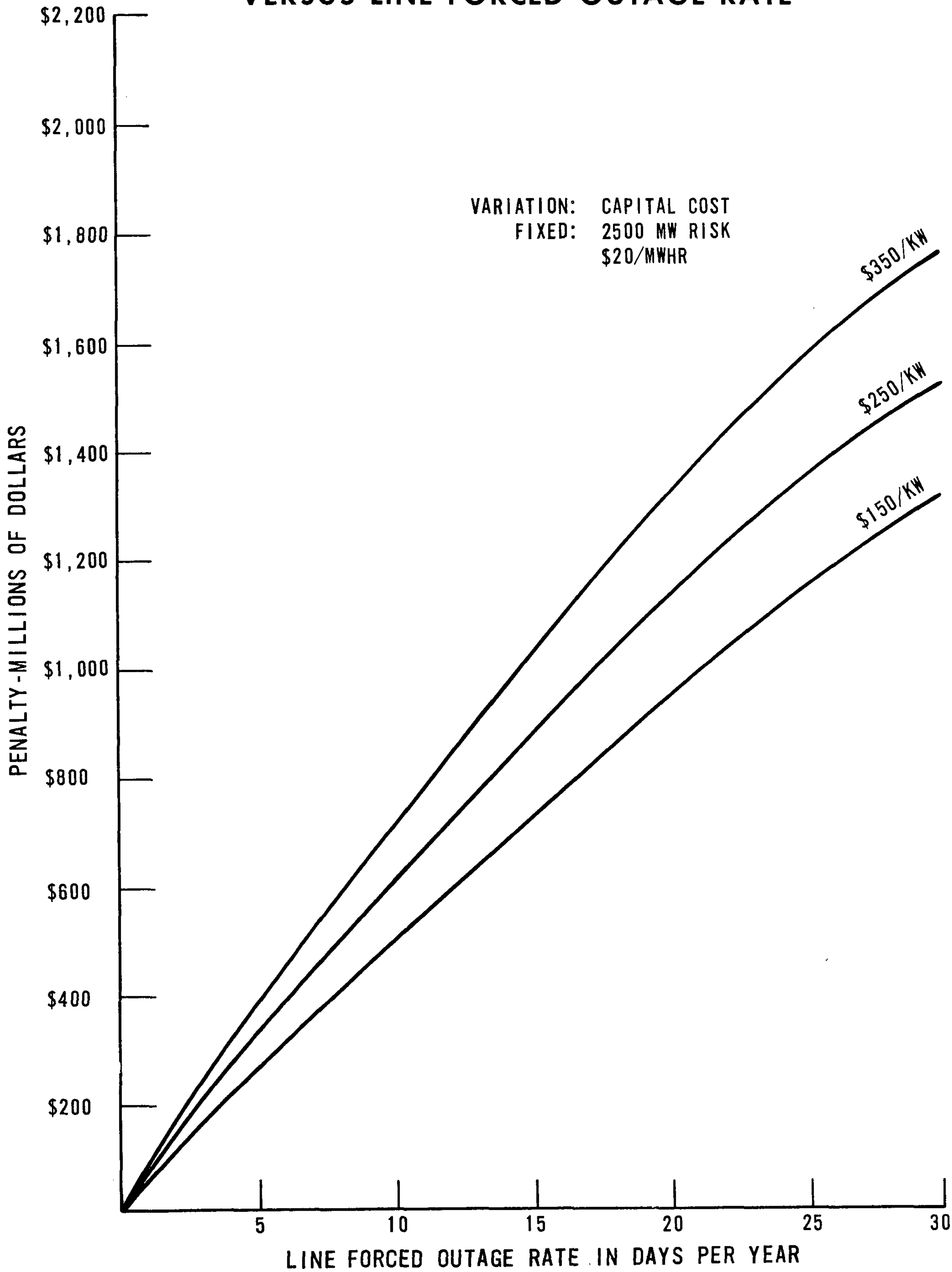


FIG. A1-2

PENALTY IN CAPITAL AND CAPITALIZED ENERGY COSTS VERSUS LINE FORCED OUTAGE RATE

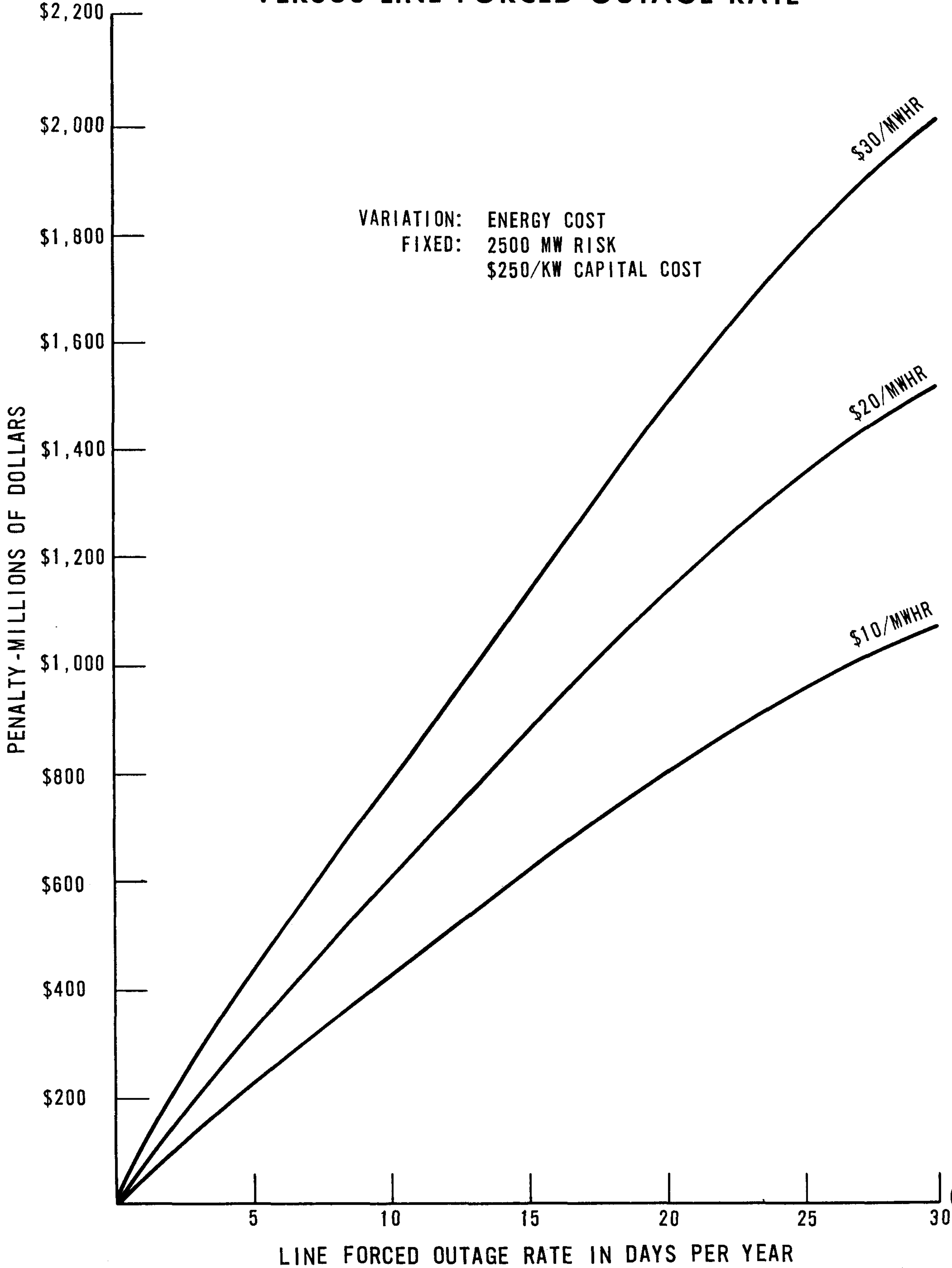


FIG. AI-3

PENALTY IN CAPITAL AND CAPITALIZED ENERGY COSTS VERSUS LINE FORCED OUTAGE RATE

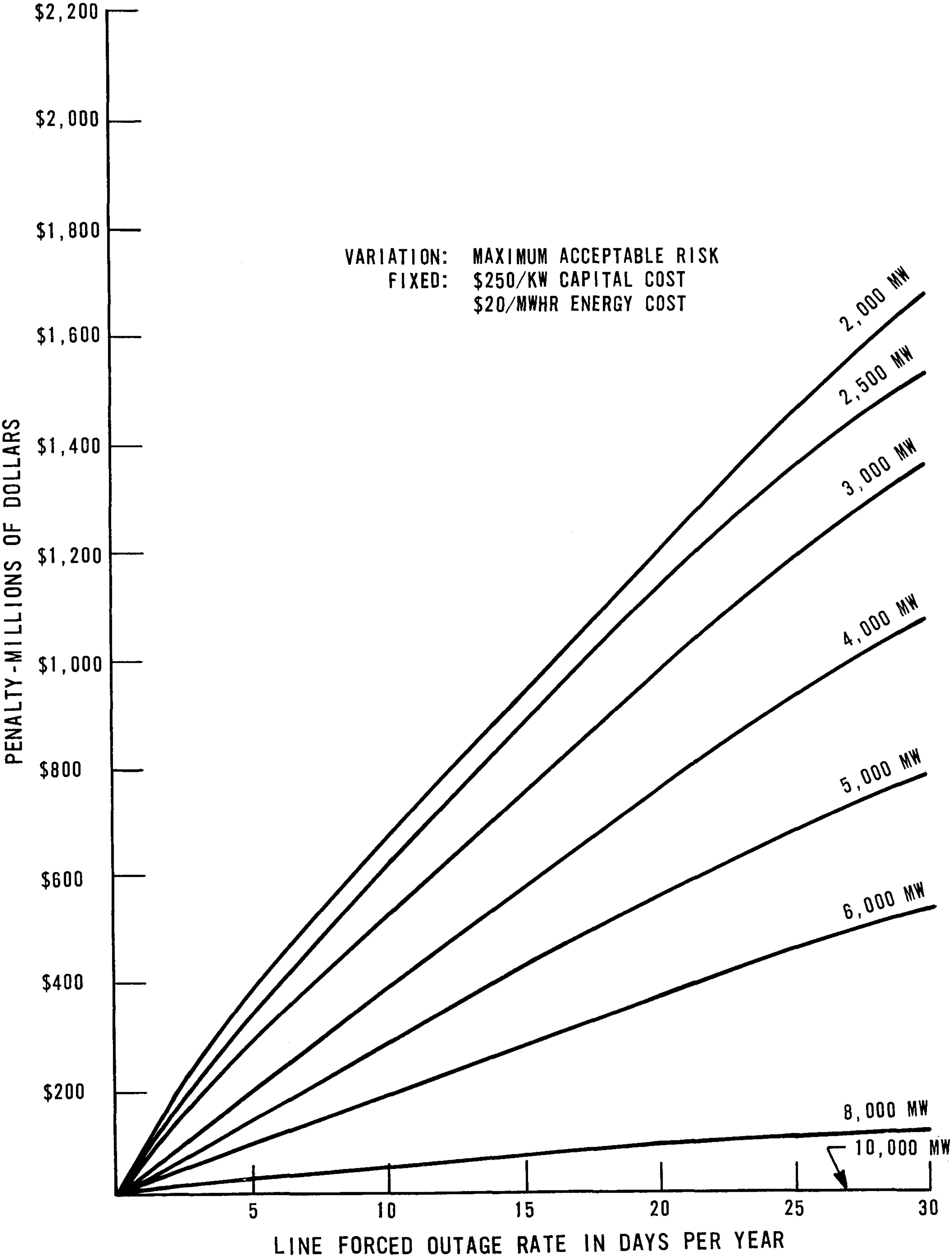


FIG. AI-4

BREAKEVEN LEVELS BETWEEN CAPITAL PENALTIES AND COST OF SYSTEM REINFORCEMENT

VERSUS LINE FORCED OUTAGE RATE

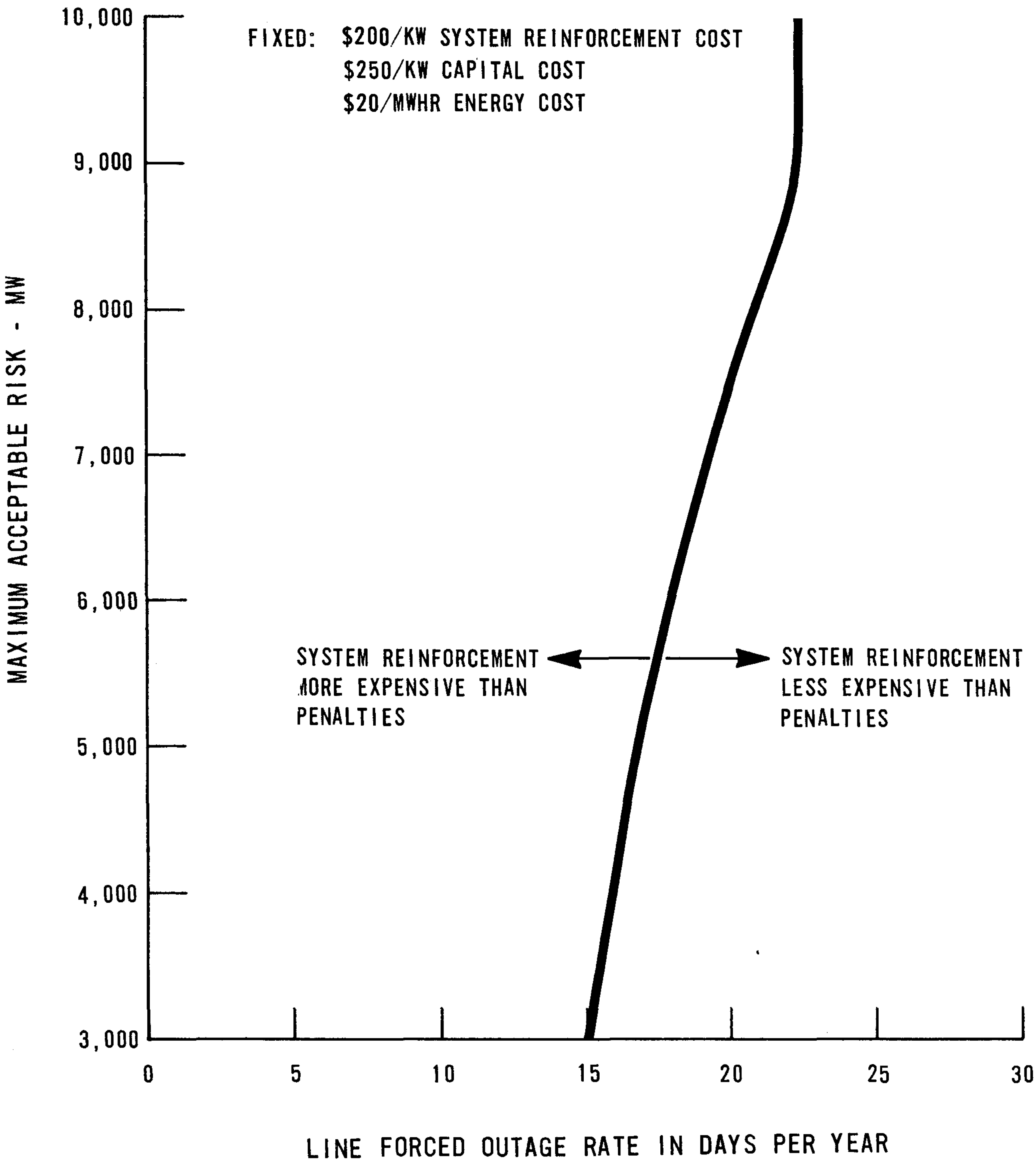


FIG. AI-5

APPENDIX II

DISCUSSIONS OF THE FINAL REPORT

A workshop on the final draft of this report was conducted by the Department of Energy in Philadelphia on September 20-21, 1977. A total of thirty-six individuals from nineteen organizations reviewed the results with the Philadelphia Electric Company Study Team and a number of comments, criticisms, and suggested corrections were aired. Most of these have been considered and taken account of in this final report.

In addition, ERDA has invited written discussions where full resolution of the comments was not feasible. These are published below, followed by a Philadelphia Electric Company closure.

GENERAL ELECTRIC COMPANY

General Electric considers that the subject report does not provide an authentic comparison of the costs of the systems evaluated because significant differences in basic assumptions were made between the various systems considered. GE notes that these assumptions were provided by the organization developing a particular system included in the PECo evaluation.

The component costs used by your study for the Resistive Cryogenic Cable were based upon estimates contained in the final GE report prepared for the Electric Power Research Institute and the U. S. Energy Research and Development Administration under Contract EX-77-C-01-2104 and Contract E(49-18)-2104. This report was prepared prior to consideration of the PECo study requirements. The objective of GE's development program was to achieve the demonstration of a highly reliable cryogenic cable system by the early 1980's. Cost data presented were based upon the following assumptions:

- Cable fabrication was based on technology available in 1975.
- Dielectric materials investigations were restricted to those readily available in 1975 from a reliable source and with uniform properties.
- Fabrication of cable system components was based upon quantities required for an installation of a single circuit of ten miles.
- Refrigeration component prices were based upon estimates supplied by vendors in 1976 for quantities required for a single circuit of ten miles.
- Component designs were not optimized from the standpoint of today's higher cost of energy losses.
- Cable reel diameters and piping lengths were limited by shipping constraints common to downtown metropolitan installations.
- Cable losses were computed using measured resistivity values for commercially available conductors and measured dielectric losses for cellulose insulation.

General Electric also considers the capital cost for refrigeration high and an undue burden for the Resistive Cryogenic Cable System. The PECo cost of $1180/kW per compressor is at least 40% higher than the $600-800/kW per compressor estimates (preliminary) obtained by General Electric from a reputable cryogenic refrigeration system manufacturer. General Electric also notes that although it was beyond the scope of the PECo study, the specific design of the refrigeration and piping system could be optimized for the PECo scenario.

Additional potential for cost reduction is feasible for the Resistive Cryogenic Cable System when viewed against the material and technological advances that can be assumed to occur by the 1990's. Specific areas for cost reduction have been identified and include:

GENERAL ELECTRIC COMPANY (cont'd)

- Development of a lower loss dielectric suitable for cable taping.
- Reduction of conservatism in the present design by measurement of the dielectric breakdown strength and thermal conductivity over the full range of operating temperatures and pressures.
- Utilization of a conductor with lower I^2R losses (i.e., higher purity aluminum or copper).
- Development of a superior thermal insulation or installation of a thicker polyurethane layer to lower the heat leak.
- Optimization of the refrigeration system to lower capital investment, installation, auxiliary equipment and operation costs.
- Elimination of one and perhaps two liquid nitrogen return lines.
- Economies of manufacture resulting from mass production of cable and refrigeration components (i.e., 264 circuit miles vs. 10 circuit miles).

General Electric and the U. S. Energy Research and Development Administration (ERDA) have contracted to pursue the development of these and other potential cost reductions under ERDA contract EC-77-C-01-5087. While this development and detailed cost analysis is required to determine the exact magnitude of these potential cost savings, significant reductions are within reach.

S. J. Fallick, Project Engineer
Cryogenic Cable Systems
ENERGY CONSERVATION AND CONVERSION SYSTEMS

GENERAL ELECTRIC COMPANY (cont'd)

We have been reviewing HVDC terminal cost assumptions applicable to Section 9 of your study and specifically Table 9-6. The basis of the terminal cost numbers used in the study is an installed rating of 4 x 2857 MW (total 11428 MW) and an equipment cost excluding installation of 214,700 K$ for the Energy Park and 230,100 K$ for Mid Site. These values represent $18.80/kW at Energy Park and $20.14/kW at Mid Site. The cost of equipment we provided to Los Alamos was $19.10/kW which we now feel can be reduced 10% as we progress on a learning curve, resulting in $17.20/kW applicable to both ends. This represents a reduction of $1.60/kW at Energy Park and $2.94/kW at Mid Site based on the 11428 MW rating. This change would then reduce the Substation Material and Equipment Cost in Table 9-6 by 51,900 K$.

As thyristor voltage ratings increase, we foresee reductions in converter terminal losses to a level of 1% per terminal compared to 1.17% assumed in the study. This would reduce the losses in Table 9-4 from 297 MW to 263 MW, and a proportional reduction of the loss evaluation in Table 9-6 from 398,500 K$ to 352,800 K$.

In Table 9-6, there is an increase of 72,000 K$ from Grand Total to Adjusted Grand Total. This is based on the difference in present worth based on the different rate of installing capacity. This penalty would be reduced if the dc terminal equipment is installed one pole at a time at the same time as each of the eight ac cables which is a realistic way to do it.

GENERAL ELECTRIC COMPANY (cont'd)

The two modifications listed earlier total 97,500 K$ and will reduce the Adjusted Grand Total in Table 9-6 from 1,422,000 K$ to 1,325,000 K$. Please consider these modifications and include their effect in your final report because in our view a more accurate comparison of conditions in the 1990's will result.

G. D. Breuer - Manager
HVDC Transmission Engineering

LOS ALAMOS SCIENTIFIC LABORATORY

1. DC circuit breakers have been used only in the case of the 300 kV dc system. Such dc circuit breakers for high-voltage power transmission are non-existent and there is no reliable way to estimate costs even roughly. It appears prudent to avoid using dc circuit breakers for point-to-point applications, such as the case considered in this study.

   A thyristor will block much faster, and perhaps more reliably, than any dc breaker could. Bearing this in mind we suggest two schemes which take full advantage of the blocking capability of a converter controllable (e.g. thyristor) valve. Isolating switches are used to isolate the faulted cable once the fault current is blocked. The proposed schemes for the Energy Park and the Mid Site are shown in Figures AII-1, AII-2, and AII-3.

   In the first scheme (Figure AII-1), power to any of the three dc SPTL's* may be interrupted by blocking the converter valves, and then opening the appropriate isolators in the ring bus. Power delivery can be resumed by deblocking the converter valves.

* Superconducting Power Transmission Line

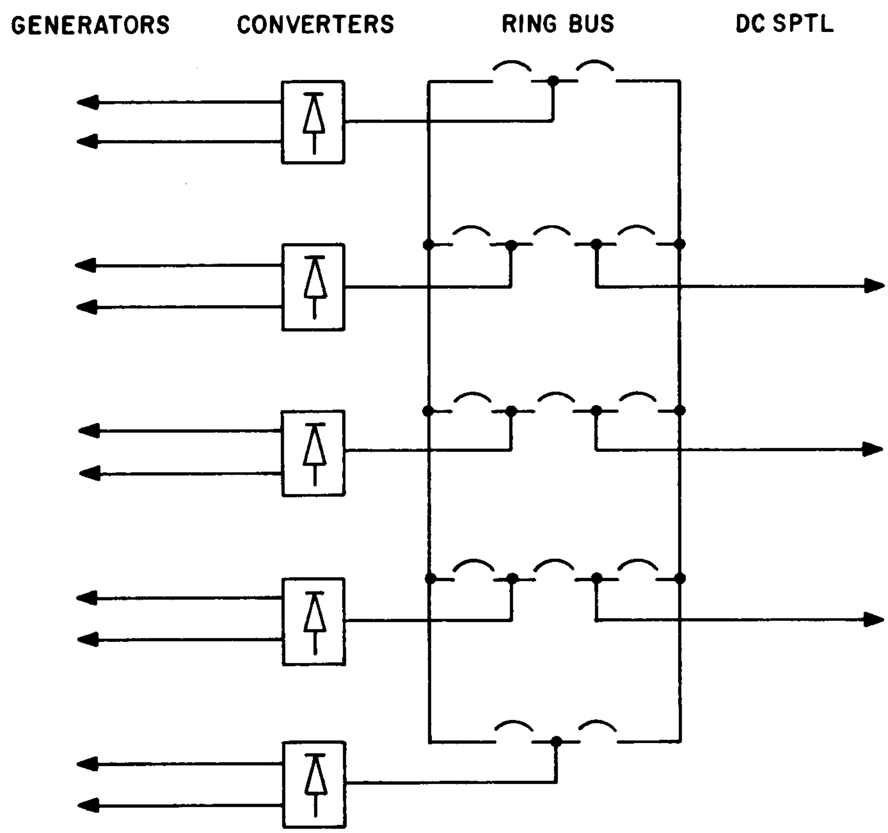
In the second scheme, two converters are connected to each cable, for normal operation. If a fault occurs in one cable, the two converters connected to this cable are blocked and the two isolating switches between these two converters and the faulted cable are opened. In the mean time, the remaining four converters connected to the other two cables keep transmitting power to the load. The two blocked and isolated converters are then reconnected, one each to the remaining cables. The whole operation will be completed in less than a second without any power interruption.

Either scheme can be used at both ends of the dc SPTL's. Scheme 1 (Figure AII-1) will be more economical than the Scheme 2 (Figures AII-2 and AII-3). Scheme 2 had the advantage that power is never interrupted. It has the added advantage that it provides flexibility in controlling power separately for each of the three dc superconducting cables. This, incidentally, will not be possible in any of the ac schemes investigated in this study.

2. For installation scheduling (Section 3.2.3), the converters should be installed at 1 GW/year/terminal in keeping with the installation of the generators(Table 4-1). This would reduce the adjusted grand total cost for the 300 kV dc superconducting cable according to your general formula.

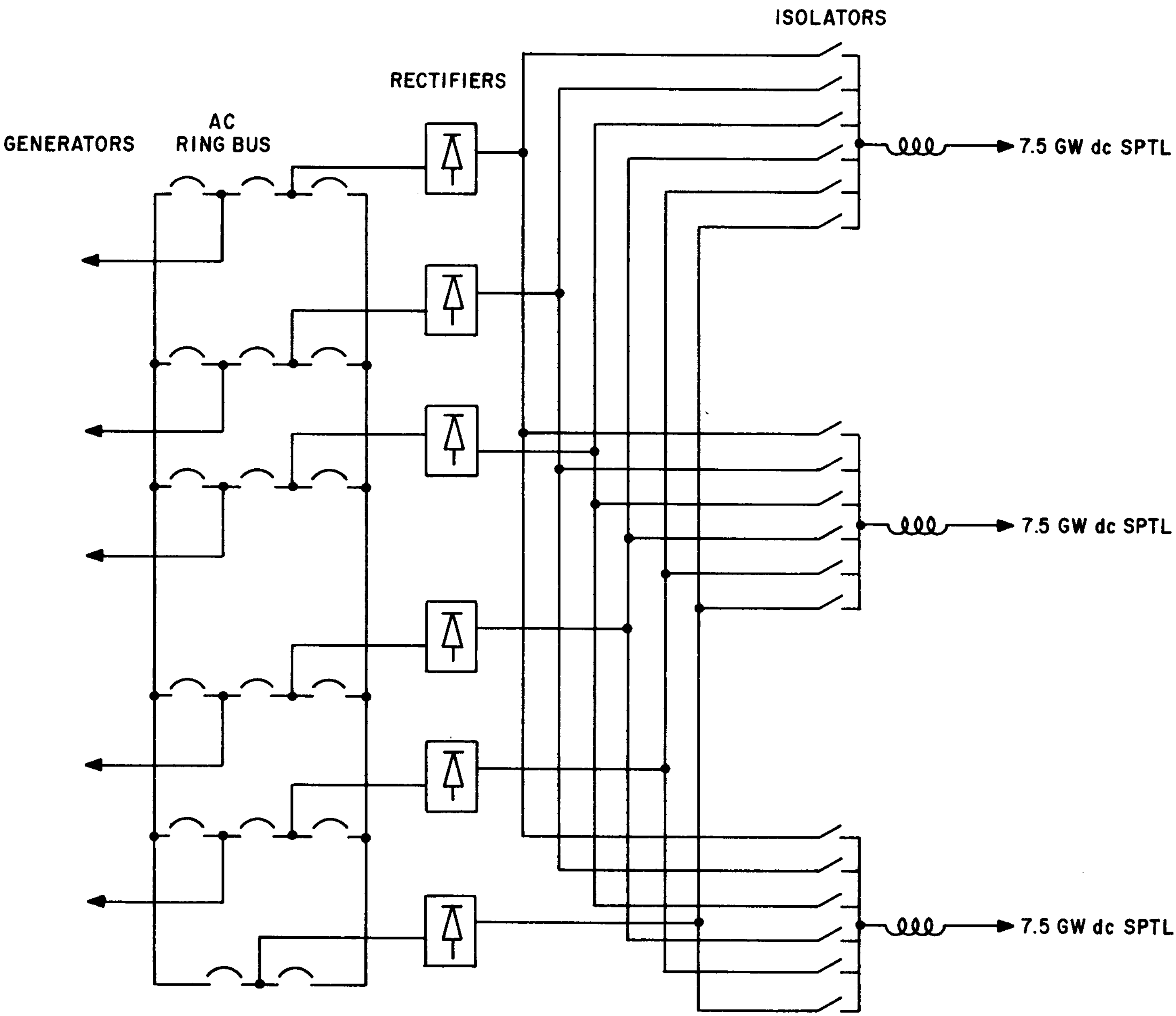
3. The method of cost estimating for cryogenic refrigerators was different from what we had expected. The large installation cost plus cost scaling by a 0.6 power law favor the installation of fewer and larger refrigerators. Had we been aware of this we would have been able to reduce the cost of the refrigeration system. Also no attempt was made to estimate the savings that would result from the simultaneous purchase of many identical refrigerators.

F. J. Edeskuty
Los Alamos Acientific Laboratory



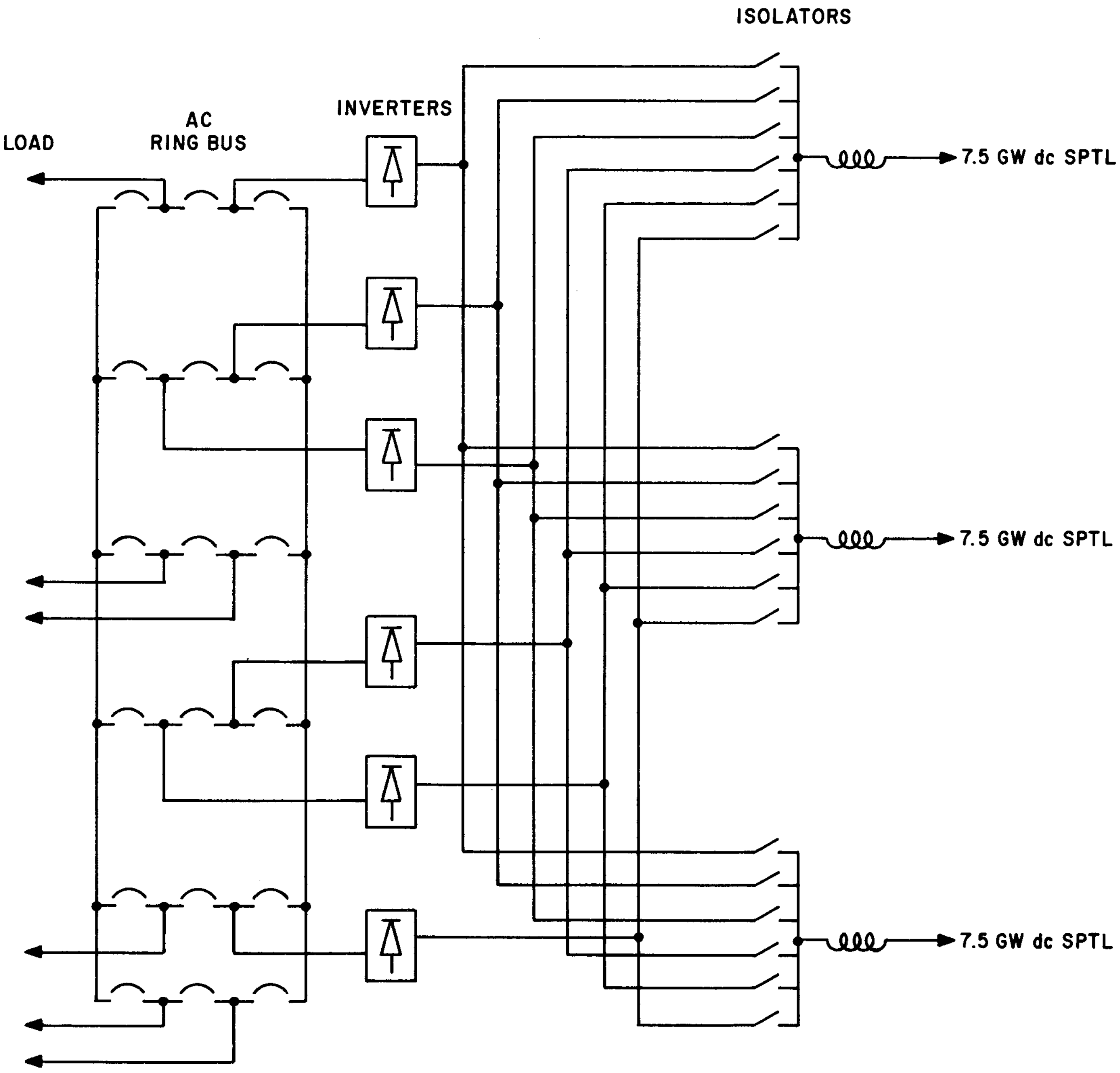
Schematic of PECO 10-GW Energy-Park Substation (Scheme I)

Figure AII-1



Schematic of PECO 10-GW Energy-Park Substation (Scheme 2)

Figure AII-2



Schematic of PECO 10-GW Mid-Site Substation (Scheme 2)

Figure AII-3

PHELPS DODGE CABLE AND WIRE COMPANY

Since the cost totals you present on Table 2-1 will be used by many people to evaluate the relative technical and economic feasibility of the proposed systems, it is critical that the systems be costed on the same basis. It is clear that the pipe type cable systems were not always compared on exactly the same basis. In the items which follow, we note the areas where the pipe type cable systems were not compared in our opinion on the same basis. We present the reasons for our opinion as well as corrections which would need to be made to your cost estimates in order to make them more nearly comparable.

1. We estimate that in the very long lengths required (about 3,000 cable miles), 500 kV HPOPT-C cable with a 2500 kcmil conductor would cost about $21/foot. This reduces the $477 million on Table 8-1 by $125 million. The reasons for this are:

   a) Our original estimates were based on lengths of a few tens of miles and do not reflect the economies of scale and mass production which would result from a 3,000 mile order.

   b) We note that 500 kV HPOPT (cellulose and PPP) have been designed on the basis of 1800 kV BIL, whereas other systems must meet only 1550 kV BIL.

   c) We have adjusted the insulation walls from 1.34" to 1.25" because the BIL is reduced from 1800 kV to 1550 kV. Based on Waltz Mill test results this is considered a proven design.

PHELPS DODGE CABLE AND WIRE COMPANY (cont'd)

2. For the very long lengths of PPP pipe type cable required, it would be feasible to set up a special plant dedicated to the production of the paper-polypropylene-paper laminate. As polypropylene resin costs less than paper (taking into account density differences) it is anticipated that in large quantities the cost of PPP could more nearly approach paper. Taking this into account, we estimate that for long lengths a 1.00" wall 500 kV HPOPT-PPP cable would cost about $23/foot. For the 765 kV HPOPT-PPP cable, we would project a cost in long lengths of $29/foot. In each case, these costs yield a savings of the order of $200 million compared to the cost used in the report. These comments also apply to the forced-cooled 500 and 765 kV PPP pipe cables.

3. We question if it is fair to eliminate DC pipe type cables without a complete economic analysis. For pipe type DC cables, if one cable is lost the other cable in the pipe is not available for further use. This means that 6 cable circuits are required assuming that each circuit (2 cables in 1 pipe) carries 2000 MVA. Again, the first contingency requirement governs as 5 times 2000 is 10,000 MVA. Whereas the second contingency would be 4 times 2000 or 8000 MVA which is greater than the required 7500 MVA. Based on 6 circuits, to get 2000 MVA/circuit, a 3250 kcmil conductor is required. Since there are no sheath losses on DC pipe cables, 3250 kcM is no problem. The cost estimate of a 3250 kcM, 1.035" wall 600 kV pipe cable would be $24/foot. Taking this cost and modifying Table 8-1 (changing # of ccts, pipe size, acreage, etc.) and using Table 9-2 (multiplying the appropriate numbers by 1.5) we find that the cost for 6 circuits of DC pipe cable is $259 million compared to the $288 million for the self-contained oil-filled DC cable (see attached Table AII-2). It appears that pipe type DC cables would cost about the same as self-contained oil-filled DC cables.

4. It seems inconsistent to require 1,760 foot pulling lengths for pipe cable (based on shipping reel limitations) and then to use longer lengths for the heavier 500 kV SCOF cable (based on obtaining special permits). We feel it should be possible to conservatively assume an average 2,500 foot pulling length for the 500 kV HPOPT (cellulose and PPP) cables. This would substantially reduce the number of manholes, splices and shipping drums but would increase the weight of each reel and require special permits for shipping over the highways. Such permits were assumed for the self-contained oil-filled cable.

5. For these very high ampacity circuits where the pipe losses preclude the use of large conductor pipe cables, it may be advantageous to consider isolated phase pipe cable. This would enable the use of larger conductors and therefore fewer circuits. Isolated phase pipe cable also may be attractive on DC.

H. C. Doepken, Jr.
E. Allam
A. L. McKean
F. A. Teti

Table AII-1

$\pm$600 kV DC PIPE CABLE

The trench design parameters used in our calculations are taken from Figure 9.4 of the Philadelphia Report with the exception that the two pipes are spaced 30 inches on centers.

Operating Conditions

Rated Voltage	600 kV (+ - DC)
Insulation Thickness	1.00"
Load Factor	100%
Pipe Size	10-3/4" O.D.
No. Cables/Pipe	2
No. Circuits	6 (2 Pipes/Trench)
Burial Depth	35.4 Inches
Spacing	-30 Inches in Trench
	-10 Feet Trench to Trench
Earth Ambient	23°C
Earth Resistivity	80°C-cm/Watt
Required Capacity	2000 MVA (1666 Amperes)
Conductor Metal	Copper

TEMPERATURE DROP (°C)

kcmil	Rating Amperes	ΔT Across Insulation	ΔT Across Oil	ΔT Across Pipe Coating	ΔT Across Backfill	Earth Interface Temperature
3250	1685	21.8	5.4	.51	2.1	55.2

The cable price is estimated to be $24/foot.

Table AII-2

CABLE SYSTEM COST
$\pm$600 kV DC Cable

		HPOPT-Cellulose P. D. Study based on P. E. Quantity	HPOPT-Cellulose P. D. Study based on P. E. * Total Cost-M$	SCOF P. E. Study Quantity	SCOF P. E. Study * Total Cost-M$
I.	Right of Way				
	1. Street	28.6 ac.		41.3 ac.	
	2. Private	286.0 ac.	4.9	418.0 ac.	7.2
II.	Clearing Access Rds.	286.0 ac.	0.4	418.0 ac.	0.5
III.	Pipe & Oil (10" pipe)				
	1. Street	36 mi.	5.3	-	-
	2. Private ROW	360 mi.	52.7	-	-
	3. Oil	6.3×10^6 gal.	10.2	-	-
IV.	Street Concrete	-	-	24 mi.	4.4
V.	Manholes	594	5.3	792	3.5
VI.	Excavating & Backfill				
	1. Street	18 mi.	12.1	24	15.8
	2. Private ROW	180 mi.	41.3	240	59.4
VII.	Cable 2-1 x 3250 kcM	396 mi.	117	-	-
	Cable 2-1 x 4000 kcM + Neut.	-	-	264 mi.	190.9
VIII.	Terminations	12 sets	0.9	8 sets	0.6
IX.	Pumping Plants	6	1.0	4	0.7
X.	Engineering		2.1		1.4
XI.	Maintenance		6.0		4.1
	TOTAL		259.2		288.5

* Total cost represents material and labor

- 6 ccts are required
- 1st contingency 5 x 2000 MVA
- 3250 kcmil @ $24/ft.
- 3 x 50" trenches, 2 lines per trench

- 4 ccts with return are required

WESTINGHOUSE ELECTRIC CORPORATION

1. Costing of GITL Systems

The price of the gas insulated transmission lines which we quoted reflect what we consider to be a realistic cost of these gas insulated transmission lines for the period under consideration; i.e., 1990. The price list which we sent to you originally with the high cost multiplier is specifically for very short lengths (e.g., 3,000 feet), mainly for use inside gas insulated substations. The manufacturing techniques presently used are specifically for these short lengths and are not really suitable for mass production for long installations. Correspondingly, there is little automation, and the labor used in these gas insulated transmission lines is at present very high, as essentially hand-craft operations are used for the manufacture and assembly of the insulators, conductors, plug-in connectors and sheath systems. As the market for GITL systems increases, it is expected that improved techniques will be introduced into the shop to dramatically reduce the labor content.

The multiplier originally quoted was only for estimating purposes and therefore included a generous margin. If one calculates the quantity of aluminum used in the GITL systems and knowing the price of the aluminum extrusions for the conductor and sheath, then one can readily confirm that the prices quoted for the 1990's are indeed realistic. These prices do not reflect any additional technological breakthrough that is to be expected in the near future. For example, the present cast epoxy insulators will undoubtedly be replaced by low dielectric constant material spacers that can be injection molded at a lower cost. Alternative methods of fabricating the high cost aluminum sheath are being developed which will also reduce the total cost. In the future, new gases or gas mixtures which are of both lower cost and higher breakdown strength than the presently used SF_6 will be introduced. This will result in a reduced size of the system, with subsequent reductions in the cost.

2. Forced Cooling of GITL Lines

The report includes an analysis of the effect of forced cooling of pipe type cables, but does not include forced cooling of GITL systems.

Westinghouse has made a detailed study of forced cooling in the EPRI Report EL-228, "Analysis of Forced Cooling of Compressed Gas Insulated Transmission Lines", December 1976. This showed that by simple forced cooling (water circulating in aluminum pipes in contact with the aluminum sheath), the current rating could be increased by a factor of 2.5. The cooling stations could be 10 miles apart, and the additional cost of the forced cooling equipment only (piping, pumps, heat exchangers, fan) was typically 5% of the GITL cost. Of course, there are also increased losses and higher present worth of losses.

It is proposed for the Philadelphia Electric study that the GITL forced cooling be used not for the continuous normal operational current, but only for the emergency or contingency conditions when a line is out of service. The lines would thus be sized so that they could take the normal continuous current. This results in significant savings as shown in Table AII-3.

2.1 Forced Cooling of Single Phase Rigid GITL System

In the Philadelphia Electric report, the rigid, single phase GITL lines are designed to have a rating such that if only two of the three lines are in operation, they can carry 5,000 MW each. As a result the 500 kV systems are very large; the conductor is 16.0 in. O.D., 0.7 in. thick, with a sheath of 26.31 in. O.D., 0.406 in. thick.

It is proposed to reduce the GITL size to have a maximum, naturally cooled rating of 3333 MW for each line. For the same burial conditions as in the report (30" soil covering, 118" interphase separation, 100% load factor, soil $\rho = 80^{\circ}C$ cm/W, $23^{\circ}C$ ambient) the rating can be achieved with almost standard 500 kV GITL dimension; i.e., conductor of 7" O.D., 0.7" wall, sheath of 20" O.D., 0.375" wall. The maximum sheath-soil interface temperature would be $59^{\circ}C$, which should be adequate for this large system as the temperature gradient in the soil will be low. The conductor temperature will be $82^{\circ}C$, well within specifications. The weight of aluminum in the system will thus be reduced from 76.4 lb. per phase foot for the 5000 MW rating to 43.2 lb. per phase foot for the 3333 MW rating, a reduction of 43%. Being pessimistic, this could result in a 21% reduction in the cost of the line. The savings in SF_6 gas due to the smaller diameter are 43%. The losses are higher by 95.6%, due to the smaller cross section of aluminum.

The cost of the forced cooling equipment is taken from EPRI Report Number EL-228, Table L-4, page 90 (500 kV, 6,000 A rating, 5 mile station separation) and totals \$100K per circuit mile.

The modifications to the costs in the Philadelphia Electric Report are given in Table AII-3, below. The substation equipment, installation, right of way, maintenance costs, and system compensating equipment are assumed to be unchanged. It can be seen that this reduces the Adjusted Grand Total by \$96,838 K to \$1,442,015 K; i.e., a reduction of 6%.

2.2 Forced Cooling of Three Conductor, Rigid 500 kV GITL

The ampacity calculations of the 500 kV three phase GITL system in Table 6-2 are such that each of the 5 lines is designed for contingency conditions with a naturally cooled rating of 2500 MVA, in case only 4 lines are in service. The sheath temperature is only 55°C, so that this is a conservative rating because, as noted in the report, the sheath temperature can certainly be higher on account of the low temperature gradient in the soil.

With forced cooling it is proposed to replace the 5 circuits with 4 circuits, each with a natural cooled rating of 2500 MVA. The emergency contingency conditions are taken account of by forced cooling all the lines. The number of the lines and substations is therefore reduced by 20%. It is assumed that the cost of the cable and installation are reduced by 20%, as the same GITL construction is used. The losses are higher by a factor of $(2500/2000)^2 = 1.56$, so the present worth of the losses are increased by this factor.

The cost of the forced cooling equipment is taken from the EPRI Forced Cooling Report, Table L-10, page 98 (500 kV, three conductor GITL, rated 5000 A, cooling station separation of 5 miles). The total equipment cost is only $44.7 K per circuit mile, as the amount of forced cooling required is small. It should be noted that this is a higher current rating than required. It is assumed that the substation and system compensation costs are reduced by 10% as a result of the fewer circuits.

From Table AII-4 it can be seen that the forced cooling of the three conductor, three circuit system results in a reduction of $112,774K compared with the naturally cooled 5 circuit system. This figure is slightly optimistic as no account is given of the installation cost, building, maintenance, real estate, or the economics for the installation schedule. These have not been calculated but might perhaps account for an additional $40,000K. Further, no spare cooling pumps, heat exchanger and fan units are supplied for reliability. These only account for 19% of the total forced cooling costs, or only $8.68K per circuit mile, the major cost being the aluminum cooling pipes, so that assuming one additional pump, heat exchanger and fan per circuit would only add $2,270K to the total. Together with the guestimated $40,000K additional costs, this would total an additional $42,270K, so that the revised Adjusted Grand Total figure for the forced cooled, 500 kV three conductor GITL system would be $1,268,203K. This would then be the lowest cost underground system, being $38,449K less than the 230 kV superconducting cable.

2.3 Forced Cooling of GITL System: Conclusions

This simplified analysis has shown the dramatic effect of forced cooling GITL lines for the emergency or contingency conditions, so as to reduce either the GITL size or the number of GITL circuits to require only the natural cooled rating when all the circuits are in operation. The analysis indicates a 6% reduction in the Grand Adjusted Total for the 500 kV isolated phase rigid design, and for the 500 kV three conductor rigid GITL system.

It would be valuable for the Philadelphia Electric-ERDA study to examine the forced cooled GITL system in more detail to verify that forced cooling for emergency conditions only is an economically attractive system.

3. Particle Contamination

Several comments were made about the "serious problem of contamination" for GITL systems. I consider that this problem has been greatly exaggerated. Some of the installations first used did not have the "particle trap" systems that are now an important design feature of the GITL systems.

The particle trap system deactivates any contamination that may be present by moving the particles in the electric field into a zero field region at the sheath where they are effectively removed from the highly stressed region of the line. The present generation of particle traps operate very successfully. Part of the installation procedure in the field is to apply the AC test voltage in steps to deliberately move the contamination into the particle traps, which are situated at all the support insulators.

There is extensive development work in progress to develop even better and more reliable trapping techniques, and it is therefore confidently expected that contamination will not be a serious problem with future GITL systems.

It is worth mentioning that the GITL systems are specifically designed to reduce the contamination that might be present. For example, the conductor plug-in contact has a special seal to prevent any contamination that might be produced entering the line. For the sheath joints which are welded in the field, there is a special design of backup ring which includes special seals specifically designed to prevent any welding contamination from entering the bus. The GITL system is a very simple design which with reasonable care almost certainly eliminates the possibility of contamination being introduced during installation and operation.

4. Consequences of Fault and Repair

The report states that in the event of a fault the contamination will extend over many sections and would make repair difficult. With the early designs of GITL there was some evidence that contamination after a fault would not just be confined within the typical 60 foot shipping length. However, with the present designs, there is at least one conical insulator in each sixty foot shipping length. The purpose of this insulator is to act as a "semi-stop" insulator, which permits gas passage but which stops contamination traveling past in the event of a fault. Therefore, if there is a fault, any arc products are confined to one standard 60 foot shipping length, and do not progress into the adjacent sections.

One of the advantages of GITL systems is that the repair is probably far quicker and simpler than any of the other cable systems being considered. The first step is to locate the fault, which is discussed in detail below. The system is then inspected by cutting a hole in the sheath, at which point it can be determined if the insulator can be readily repaired, for example by sanding the surface and general cleanup. This is a very fast procedure and techniques have been developed specifically for cutting holes in the sheath and for aluminum repair patches to be welded over the hole after the cleanup. If it is apparent that the damage is very severe, then the procedure would be to remove that 60 foot shipping length and replace it with another spare GITL section. The repair procedure would be to cut through the sheath welds and remove the damaged section. A specially designed GITL section would then be used for replacement with a rapid conductor plug-in joint and with a simple sheath welded joint. It is estimated that with the appropriate equipment the damaged section can be removed and replaced back in operation certainly within 48 hours. If very large vacuum pumps and improved gas handling systems are available it may be possible to reduce this time from the location of the fault to back in service to 24 hours. No tape wrapping or special handling techniques are necessary, and the training needed for the personnel is minimal. Any damaged section would be shipped back to the factory for repair and returned as a spare.

5. Fault Location

The report comments that fault location on GITL systems is a serious problem. On systems which are only a few hundred feet in length, the fault can be located using a straightforward sonic detection system. This locates the sound of the arc traveling through the aluminum sheath, and can be used to locate the fault to typically within one foot. However for long lengths different techniques will have to be used. It is becoming apparent that the traveling wave technique can be used for even long lengths of transmission line. In this technique a high voltage surge is applied to the line and the time measured for the voltage collapse to be transmitted back.

It is expected that by the year 1990 there will be advanced fault location techniques developed and proven. These will probably be a two-step process to first locate the fault to the appropriate 60 foot section length, with additional sonic techniques to then locate to within a few inches. There is expected to be an RFP from EPRI specifically with this as a goal.

6. Conductor Plug-in Joint

The differential thermal expansion between the conductor and the sheath is accommodated by a plug-in joint on the conductors. These plug-in joints are the result of extensive development, as it has been necessary to develop a joint with very low wear characteristics, and one which can sustain the load and short circuit currents. The present generation of plug-in contacts have been extensively tested; for example, a typical test has been to operate the plug-in joint mechanically cycled over the full movement for 50,000 cycles operating at full load current. This is equivalent to 3 full thermal cycles a day for well over 40 years. At the end of these tests there is negligible increase in the contact resistance and negligible increase in temperature rise at the joint. For this reason there is every confidence in the operation of the joints.

It is expected that future developments will substantially reduce the cost of these plug-in joints, although this has not been included in the future quoted price of the GITL systems.

7. Insulating Supports

The present spacers or insulating supports used for gas insulated transmission lines are of cast epoxy. There has been extensive high voltage testing to verify the electrical performance of these insulators both for external flashover and for the internal dielectric strength. All the insulators on GITL systems are high voltage tested before they are assembled on the conductors and the completed assemblies are also given a high voltage test. Experience has shown that these cast epoxy insulators are adequate.

The insulators used for the isolated phase systems experience negligible forces, even during short circuit tests. However, the three conductor GITL system must be designed to withstand the short circuit forces that occur. As a result the post insulators for the three conductor systems are of a more rugged construction than for the isolated phase system. It is worth pointing out that the three conductor GITL system developed on the EPRI program referred to later passed all the short circuit tests at 63 kA.

Future generations of GITL systems will undoubtedly replace the expensive cast epoxy insulators with injection molded plastic insulators for a fraction of the cost. There are several programs in progress which will achieve this aim within the next five years. This improved cost has not been included in the future GITL costs referred to previously. In present GITL systems the cost of the insulators typically amounts to 10 to 15% of the total material cost, so one can see the area for future improvement.

One of the questions at the meeting referred to forces on the insulator due to differential thermal expansion between the conductor and the sheath. There is no such force on the insulators as there are sliding contacts, either the conductor sliding inside the insulator or the insulator sliding inside the sheath.

8. Three Conductor GITL Systems

Westinghouse has just completed a program for EPRI for the development and test of a three conductor, 345 kV GITL system of an optimized design. The final report has just been completed. Two prototypes passed all of the high voltage and short circuit tests, and the program verified the technical design. The economic analysis confirms that three conductor GITL systems offer a potential 10 to 15% installed cost reduction compared with the rigid isolated phase systems. Because of this program we consider that three conductor GITL systems are now past the development stage and are a technically proven system, ready for installation on a utility system. EPRI has issued an RFP for a program with Westinghouse and a cooperating electric utility to install a 300' length of the three conductor design on a 345 kV system so as to obtain the operational experience for the utility and the large scale manufacturing experience of the GITL.

9. Corrosion Protection

The report raises the question of the reliability of the corrosion protection used for the aluminum sheath of the GITL system. The corrosion protection presently used for these systems is to use an extruded polyethylene coating on the outside of the sheath, typically 60 mils thick, which is extruded over a polybutyl rubber adhesive typically of 20 mils thickness. This is a system which has been developed and tested for steel pipeline systems. As a secondary corrosion protection, a sacrificial zinc anode is used to protect against any pinholes that may exist in the coating. To date this corrosion protection system has been satisfactory and no problems have arisen, even with one system which exists in a tidal area and which is frequently submerged.

10. Elbows

For the rigid isolated phase and three conductor system, prefabricated elbows, either assembled to the bus in the factory or with a plug-in system in the field, accommodate major changes in the direction of the GITL system. It is worth noting that although these systems are considered rigid they do have a certain amount of flexibility; a 60 foot length can readily accommodate the end being moved through a distance of one foot. The conductor plug-in joint and the sheath joint are designed to accommodate a change in direction of $\pm 2^{\circ}$. It would be interesting to know what assumptions were made in the study for the flexibility of these rigid systems and to know if the above additional information would have had any significant effect on the installed cost. It would be of interest to have the cost breakdown for the elbows and GITL straight sections for the rigid isolated phase and the three conductor systems. It is becoming apparent that it may be possible to replace the expensive forged elbows presently used for buried systems with mitered elbows of typically half the cost. It would be interesting to know the effect this would have on the installed cost.

It would also be valuable to know what was the minimum radius that the flexible GITL had to assume during installation. Were there many really sharp bends, or were most of the bends of a fairly large radius, for example, 50 feet? This is relevant because it may be possible to optimize the design of the flexible GITL system with a less sharp bending radius. The fact that the flexible system would be installed in 60 foot lengths rather than the longer lengths would have a small effect on the price, as the plug-in joints are a small percentage of the total cost. This information on the typical minimum bending radius could have a significant effect on the future design of these flexible GITL systems. Also, for the installation of the flexible system, was it assumed that the GITL was being pulled through the trench, or that the trench was open and that the flexible system was contoured to the required profile and lowered into the trench?

11. 765 kV GITL Systems

The study examined 765 kV forced cooled oil cables, but did not include 765 kV GITL systems, even though these have already been built and tested in the rigid single phase design.

An increase in system voltage to 765 kV and the resultant reduced current rating would have a significant effect. The 500 kV GITL isolated phase rigid system selected for the current rating (16" O.D. conductor, 0.7" wall, 26.31" O.D. sheath, 0.406" wall) is virtually the same outside diameter as the isolated phase 765 kV system. This is sized with a conductor 8" O.D., 0.7" wall, sheath 25" O.D., 0.25" wall. The standard isolated phase 765 kV system uses 34% less aluminum than the high current rating 500 kV GITL system in the report and would then be at least 17% lower in cost.

An even larger effect of introducing 765 kV system voltage will be present with the three conductor and flexible GITL systems where it will probably be possible to reduce the system from 5 to 4 naturally cooled cables because of the lower current rating requirements at 765 kV.

It is apparent that substantial savings could be made with 765 kV GITL systems, and that it would be of interest if the detailed analysis were made.

12. General Comments

The report is extremely good and for the first time looks at the total effective installed cost of a long line, high voltage, underground transmission length. The sections considering the stability and the additional costs used for substations, compensation and losses are obviously important factors which must be considered in future system evaluations.

Alan H. Cookson, Manager
CGIT Research and Development

Table AII-3

FORCED COOLING COST OF ISOLATED PHASE 500 kV GITL

		Naturally Cooled System $K	Forced Cooled System $K	Difference $K
1.	GITL System (Table 10.1, III)	768,381	607,021	-161,360
2.	SF_6 Gas (Table 10.1)	58,128	33,132	- 24,995
3.	Forced Cooling Equipment	0	19,800	+ 19,800
4.	Present Worth Losses (Table 10.5, Cable)	72,926	142,643	+ 69,717
			TOTAL DIFFERENCE	$ - 96,838 K

Radial System, Adjusted Total

Naturally Cooled	$1,538,853 K
Forced Cooled	$1,442,015 K

Table AII-4

FORCED COOLING OF 500 kV THREE CONDUCTOR GITL

		Naturally Cooled System $K	Forced Cooled System $K	Difference $K
1.	GITL System (Table 10.3)	5 circuits 994,354	4 circuits 795,483	-198,870
2.	Substation & Compensation (Table 10.5)	127,501	114,750	- 12,750
3.	Forced Cooling Equipment	-0-	11,800	+ 11,800
4.	Present Worth & Losses (Cable & Substation) Table 10.5	155,441	242,487	+ 87,046
			TOTAL DIFFERENCE	$ -112,774 K

Radial System Adjusted Total

Naturally Cooled $1,338,707 K

Forced Cooled $1,225,933 K

BONNEVILLE POWER ADMINISTRATION

1. The average transmission distance in the Northwest is more than double the distances mentioned in the introductions to the report. This trend in the Northwest is likely to continue and possibly increase. The report should state that longer distances will make DC systems more attractive.

2. In any study of this type, the basic assumptions concerning reliability, power levels, transmission distances, cost of losses, interest rate, etc., have a very significant effect on the final results. In general, the authors have clearly identified the assumptions and quite rightly cautioned against the use of the results without regard to the assumptions. However, if the results of the study are to be of general use, there should be some type of sensitivity analysis of the impact of varying some of the assumptions.

3. For a fair comparison of different technological solutions, some effort should be made to arrive at an equivalent level of optimization. Some detailed explanation of the present status and direction of each technology is appropriate. We are particularly interested in the detailed basis for the estimates of DC terminal costs.

4. High-speed circuit breakers, say one cycle with very high interrupting capability as well as continuous duty ratings, can be obtained today at appropriate prices. There is no need to wait until the 1990's.

5. We recommend including a 1200-kV system as one of the alternates for evaluation in the report.

6. As indicated in the introduction to the report, the cost of gas-insulated transmission lines is "assumed to be approximately sixty percent of present cost". This is highly speculative and not consistent with assumptions for the other systems considered in the report.

7. In Section 3.2.1 of the report, carrying charges are evaluated at 16.3 percent. This is appropriate for the private sector of the industry. The study should take into account that publicly financed utilities may have a lower annual cost ratio.

8. Section 3.2.2 needs a better justification for the value of losses. Some of the parameters appear high, while others appear low. Since the value of power and energy losses are critical factors in evaluation of alternatives, they deserve significant explanation. The value of power for losses may indeed be the controlling factor in selection of facilities for future transmission systems, accompanied by environmental constraints. It is generally accepted that incremental losses should be evaluated against incremental resources. Presumably, this has been done in the study, but it needs further clarification for the benefit of the industry. It would be helpful to include a sample calculation for the present worth of losses in the report.

9. In Section 4, generating complexes of 10 GW are contemplated. These may be too small on a national scope when considering energy requirements through the end of the century or shortly beyond. Though the scenario is appropriate in the short range, it would be beneficial to the report to discuss long-range requirements. An appropriate planning horizon for the entire electric utility industry

would be at least the year 2020 and possibly longer. The effect of 30 GW, or 40 GW complexes on the results of the report should be discussed. Though very long-range planning is foggy, it gives insight to minimize the constraints planners impose today.

10. In Section 4.3.1.2, reference is made to reliability criteria that permits dropping 2,500 MW of generation for long periods for a single contingency outage on the transmission system. This represents a significant generation spinning reserve responsibility available to the load areas. The economic sensitivity of this assumption should be further investigated.

11. Under Section 3.4.2, we suggest that EEI data would be more appropriate than data from two existing generators on the system when considering future generating capacity.

12. Section 4.3.3 indicates that series reactors are required to limit powerflow on the cables operating in parallel with the existing system. Other systems that have a stiffer existing network may not require series reactors. Is it expected that there are several systems in the U. S. that will have this condition in the future?

13. In Section 4.4.6.3, it is stated that "An increase in the fault duties could cause an increase in the time required to clear the fault." It would be helpful to include an explanation of the basis on which this statement was made.

14. In Section 5.7.1, it should be pointed out that d-c terminals have a much higher availability than nuclear generating units.

15. The analysis was based on fully compensating the line charging current with shunt reactors. This may be overly conservative since the line will be somewhat self-compensating when it is loaded. It may be possible that under less than full load conditions, it would be more economical to deenergize several of these circuits and operate the remaining circuits at a higher load. This mode of operation would reduce the need for some of the shunt compensation. An analysis would need to be made of the cost of losses versus the reduced cost of compensation.

16. A contingency factor of 10 percent is used in the calculation of substation costs. It does not appear that a similar factor was applied for the transmission part. Therefore, systems with a high ratio of substation-to-line cost suffer in comparison.

17. The thermal criteria and analysis should include current EPRI and industry studies on soil additives that provide thermal stabilization and low thermal resistitivities.

18. For the 600 kV Self-Contained Oil-Filled D-C Cable System, there are four bipolar circuits each with neutral return conductor providing eight separate circuits. Such a large number of circuits are required only because of the assumed maximum capacity of 1500 MW per cable. There should be more discussion about the feasibility of higher capacity systems, either by increasing ampacity of 600 kV cables, or by using higher voltages.

BONNEVILLE POWER ADMINISTRATION

19. A comparison of the alternates with cellulose versus PPP seems to imply a big advantage in the use of PPP. If the insulation thickness for cellulose were reduced from 1.34 inches to 1.25 inches, how much would this reduce the advantage in using PPP?

C. F. Clark
Branch of Transmission Engineering

PHILADELPHIA ELECTRIC COMPANY CLOSURE

The comments above are well taken, and include a number of suggestions for further work or study. Unfortunately, many of the proposals are beyond the scope of the study as outlined and approved by the sponsor, and cannot be addressed without extending unduly the cost and time of completion of this evaluation. Further analysis must, therefore, await future study programs.

Those comments on which the study team is able to respond are as follows:

In answer to the General Electric letter from Mr. Breuer, the HVDC terminal costs are based upon the initial GECo estimates. Since it is our Company practice to participate in design decisions on turn key projects, the final cost estimate is larger than the GE estimate by engineering and field supervisory costs. While it is recognized that some emerging technologies can be expected to reduce costs as designs mature, no attempt was made to incorporate this into the HVDC terminal substations.

PHILADELPHIA ELECTRIC COMPANY CLOSURE (cont'd)

The suggestion to reduce costs by installing one dc pole at a time might save money, but we perceive system operating problems since the installation and testing of capacity additions in this manner requires extensive and prolonged outages on existing equipment. A high capacity generation and transmission system addition would have to be made in such a way as to minimize outage requirements for construction.

Los Alamos Scientific Laboratory has introduced an alternate 300 kV dc substation arrangement in Figures AII-2 and AII-3 of their discussion. This suggestion, which eliminates dc breakers, does not appear to us to produce a clean-cut cost saving. LASL has produced a net saving of 15,000 K$ by reducing rectifier capacity and associated equipment from 12,000 MW to 10,000 MW, but this does not allow capacity for all contingencies. However, the dollar changes above do not affect materially the total system cost.

The suggestion to install converters at a rate of 1 GW/year theoretically would reduce the Adjusted Grand Total. However, the savings would occur only at the Mid-Site Station since the converters at Energy Park are already installed at a rate of 1 GW/year with the installation of each generating unit. The problems mentioned above with the addition of one dc pole at a time also occur at Mid-Site if 1 GW/year of conversion capacity is planned.

In response to the comments of Phelps Dodge, the purpose of the study was not to make an evaluation of dc systems. The dc application was included to provide an ac to dc comparison of what appeared to be the most economical dc design. No attempt was made to optimize alternative dc cable designs, and additional study of the dc systems may well support the Phelps Dodge comments.

We would like to point out, however, that the highest cost item in Table AII-2 is Item VII, Cable Cost, which is approximately one-half of the total cost. The cost of the HPOPT-DC cable is listed as $24/foot, which is a price that appears to have been developed on a different basis and is significantly lower than the previously supplied ac cable costs. Hence, this cannot be compared directly with the costs in our report. Using SCOF cable costs derived on the same basis as HPOPT cable probably would indicate the SCOF cable to be less expensive. However, it is possible that the HPOPT cable could still be less expensive in city streets, which is the more likely installation location.

Section 3.10 of the report has been revised in response to comment number 4. However, based on the HPOPT costs, the effect of changing the cable pulling lengths and splicing locations 20 percent would change the system costs by less than 1 percent of the Grand Total.

Westinghouse apparently gathers from our report that sheath temperatures above 55°C were viable with large diameter GITL pipes because of low thermal gradients. While undoubtedly there is some merit to this position, we believe there is a need for more investigation, particularly with respect to the thermal disturbance on the surface above the trench, where the environmental effects will be greater than with smaller pipes.

The comments requested data concerning the bending requirements of rigid GITL cable. The study showed that more elbows were required on the private right-of-way due to a greater number of vertical changes in elevation. In the city streets, most elbows were required to avoid other underground obstructions at intersections. Mitered elbows were used throughout.

Included in their comments is a question on the minimum bending radius and the frequency of sharp bends that flexible GITL had to take. This study assumed that flexible GITL could accommodate to the same trench as designed for the HPOPT cable system and that it would be lowered in the trench. The designer could use a 300-foot natural radius and could assume bends could be made down to approximately 25 feet in the field. Design drawings were not included as part of this study, but would be required to determine the frequency of offsets in actual installations. Even then, additional obstacles requiring offsets would be expected to be found when the trench was opened.

An evaluation of GITL flexible design versus rigid should consider the material costs, trenching trade-offs, frequency of bends, and relative field bending costs. Such study should also consider that unknown obstacles revealed during excavation could affect the relative advantages.

We have responses we would like to make to several of the comments of the Bonneville Power Administration:

8. As an example for expanding on the application of Section 3.2.2, on capitalized cost of losses, Table 8-7, Item II, for 500 kV PPP-insulated HPOPT cables was derived as follows:

   Energy Cost per Year =

$$521{,}000 \text{ MWh} \times 1.76¢/\text{kWh} \times .01\ \$/¢ \times 1000\ \frac{\text{kWh}}{\text{MWh}} = \$9{,}176{,}640$$

Capitalized Energy Cost =

$9,176,640 x (1/.163 carrying charge) = $56,297,768

Demand Cost =

$$84.6 \text{ MW} \times \$460 \times 1000 \frac{\text{kW}}{\text{MW}} = \$38,916,000$$

Subtotal 56,298 K$ + 38,916 K$ = 95,214 K$

11. We are not aware of generalized industry data on generator constants. Those we used were readily available and are representative of coal-fired and nuclear-fueled generators operating in the eastern United States.

13. Higher fault duties would require additional sequential relaying to bring short circuit currents within the interrupting capability of the breakers. This additional relaying could increase the fault clearing time.

16. Contingencies were included also in the transmission portions, but were distributed through the various items rather than lumped. Nominally a 10 percent figure was used; however, this value did vary between systems. For example, a higher contingency was applied to trenching, backfill and installation costs in city streets because of expected difficulties in bending around obstacles. A uniform 15% contingency was applied to the cryogenic refrigeration plant, which appeared to be more customary for equipment of this type.

PHILADELPHIA ELECTRIC COMPANY CLOSURE (cont'd)

18. We have not assumed deenergization of lines under less than full load conditions in order to reduce compensation requirements, since this is not usual operating practice. Lines generally are energized continuously to minimize thermal cycling, to avoid unnecessary switching, and to provide more availability for contingencies. The economic gains from reduced compensation and reduced dielectric losses appear marginal, particularly since load losses increase under such intermittent operation.

19. The material cost savings due to reduced PPP insulation wall would be small, and the cost of losses would increase slightly due to additional dielectric losses.