

Development of a Leak-Location System for  
Use on Underground Electric Power  
Transmission Cable

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## ABSTRACT

This report describes a study to evaluate methods for locating leaks of dielectric fluid from buried high-voltage cable systems. Two primary types of leak location systems were investigated: (1) systems that will rapidly isolate the leak within a manhole section, typically 1000-m long on a feeder that might be 30-km long, and (2) systems that will then pinpoint the location of the leak.

Rapid leak isolation was accomplished by developing an enhanced conductivity oil probe which allows the injection of a small quantity of conductive oil and which indicates the path of the oil as it drifts downstream in the direction of the leak.

Two methods for pinpointing the leak were proven. The more successful method was the use of trained leak location dogs which were found to have far better sensitivity than instruments and which could detect cable oil alone without the need for additives. A tracer gas injection and detection scheme was developed for use in areas where the dogs may be unsuitable.

Many other leak location methods were evaluated, and they may have application in unusual conditions. The body of the report contains a detailed description of all methods that were investigated.



## EPRI PERSPECTIVE

### PROJECT DESCRIPTION

In highly populated urban areas, large-capacity underground transmission cables provide vital links to the rest of the utility system. The most commonly used cable system is the high-pressure oil-filled (HPOF) pipe-type cable. Although these systems are electrically reliable, cable fluid leaks caused by rupture of other underground utilities and normal corrosion still remain a major problem causing forced outages. Maintenance procedures currently used to locate and repair these fluid leaks are costly and time consuming. Described in this final report are many techniques and instruments useful in detecting and, more importantly, in locating cable fluid leaks in HPOF pipe-type circuits.

### PROJECT OBJECTIVES

The primary objective of this 48-month research project (RP7869-1) is the investigation of novel leak location techniques holding the potential of reducing the maintenance costs and man-hours presently incurred by standard utility practices. Inherent in this study is the investigation of state-of-the-art techniques and viable modifications to these techniques that may reduce the cost and time associated with cable repair.

## PROJECT RESULTS

Probably the most significant conclusion, after testing many methods, is that no one technique or instrument can be used to locate dielectric fluid leak regions quickly and accurately. A hybrid system must be used, incorporating a technique or instrument that can quickly narrow the leak down to a region, and then an accurate (but slower) technique must be applied to pinpoint the leak within this defined region. Most of the hardware analyzed fall into these two modes of operation:

- Regional Techniques
  - Flow meters
  - Differential thermal probes
  - Enhanced conductivity probes
  - Differential pressure indicators
  
- Pinpointing Techniques
  - Halogen-tracer gas detectors
  - Ground-penetrating radar
  - Trained canines
  - Microphonics (sound detection)

Also presented in this final report are conclusions drawn from field tests of both conventional and novel leak location techniques. Equipment performance and comments are based only on the particular design or manufacturer. These conclusions would not hold true for other detection systems using the same mode of operation.

To realize their full potential as a maintenance tool, canines and ground-penetrating radar need further investigation. Follow-on work, sponsored by others both inside and outside of EPRI, is continuing.

Thomas J. Rodenbaugh, Project Manager  
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## SUMMARY

In recognition of the seriousness of the problem of leaks from buried transmission cable systems, the Electric Power Research Institute funded a program with Power Technologies, Inc. to develop a rapid and reliable system to locate leaks of pressurizing fluid from the cable. The program was to investigate several alternative methods of leak location, perform the necessary laboratory and field evaluations of the systems that appeared promising, and test a prototype unit suitable for utility use. The 2-1/2 year program was completed in May, 1981.

A state of the art review was performed to ascertain the current procedures for locating leaks on buried cable systems, to investigate other methods that have been attempted on cable systems, and to determine the state of the art for leak location procedures in non-cable areas such as oil pipeline leak location. A large number of systems were found for locating leaks from buried structures. Most were inherently unsuitable to a high voltage cable system but a few systems, including ones currently in use for cables, seemed to offer sufficient merit that further experimental evaluations were conducted.

The leak location study focused on high pressure oil filled pipe-type cable, which is the system in most common use in the U.S.

A typical cable circuit may be 24 kilometers (15 miles) long; each of the methods evaluated for pinpointing a leak was time-consuming so initial efforts were

directed toward developing a system that could rapidly isolate the leak to a length of pipe between two splices (typically 600-1200 meters, 2000-4000 feet).

The Thermal Probe, which has been successfully used on feeders filled with higher viscosity oil, was modified to be more sensitive but often gave erroneous readings with low viscosity filling oils commonly used on forced cooled cable systems. An Enhanced Conductivity Oil probe was developed that injects a small quantity of cable oil that has been modified to have a high conductivity. The modified oil flows downstream with the leak and bridges one or more pairs of electrodes in the probe causing the lighting of appropriate LED's in an array on a control box. The enhanced-conductivity oil is then removed by opening a bleed valve on the probe housing. The probe was shown to be sensitive down to flows as low as 4 liters/hour (1 gallon/hour) when installed in the cable line pipe and 15 liters/hour (4 gallons hour) when installed in the largest diameter joint casing.

A probe assembly, with control and output box, was given to EPRI along with a quantity of modified polybutene and mineral oil.

A major problem was uncovered in the use of any probe that is installed in the cable pipe. Monitoring of flow streams by injection of dyes into a full size clear acrylic joint casing with adjacent line pipe showed natural convection currents that were often far larger than the downstream migration of the oil due to a leak. These convection currents are due to small temperature differences along the length of the cable pipe, and explain recent incorrect readings obtained in the field. Suggestions are presented in the report to reduce these currents, which are strongly dependent upon the viscosity of the filling oil, but it does not appear possible to eliminate them completely. In addition, two methods were proposed to possibly obtain correct flow indications in spite of the convection currents. The methods are complex and were not evaluated experimentally in the leak location program.

The leak can be isolated to a two to three manhole length even in the presence of circulating currents by taking readings in adjacent manholes, and one of the proven methods to pinpoint leaks can then be applied over that length of pipe.

Leak Location Dogs proved to be successful in detecting subsurface cable oil, even in the heavy traffic of city streets and the presence of distractants such as motor oil on the streets.

Two organizations trained three leak location dogs each as part of the leak location program. The dogs were thoroughly proven in tests in the training organizations' home towns, at PTI's Saratoga test site and in tests staged by Con Edison in New York City streets. In addition, the dogs were used successfully to locate two actual leaks that occurred on a utility system during the training program.

The leak location dogs have several advantages over more conventional methods of pinpointing a leak:

- No additive is needed in the oil--the odor that the dogs seek enters the ground from the first moment of the leak.
- As a corollary, there is no concern for long-term compatibility with the cable dielectric, as there is with tracer gases.
- The dogs move at a rapid pace and are far more efficient at gathering air samples than any man-made instrument.
- The dogs are well suited to finding leaks from self-contained cables, and one dog was even trained to the odor of SF<sub>6</sub>.

The dogs were thoroughly proven under the leak location program, and the two organizations are under contract to Con Edison in 1981-1982 for further training and for use in the event of leaks. Initial searches under the new contract were not successful, however, apparently because the oil went directly into a sewer and vapors did not reach the surface.

Tracer gases were also pursued as a more conventional method of leak location. A lengthy list of potential tracer gases was generated based upon their detectability, background level in atmosphere, cost and cost of detection, and anticipated compatibility with the paper/oil dielectric system. The list was thinned to four candidates showing the most promise: helium, SF<sub>6</sub>, c-C<sub>4</sub>F<sub>8</sub>, and CF<sub>4</sub>.

Compatibility tests were performed on those gases plus aged and unaged samples with nitrogen added as a control. The tests were subcontracted to IREQ. Model cables were made and impregnated with a mixture of mineral impregnating oil and polybutene filling oil, a realistic level of contaminants was added, and the oils were saturated with the tracer at 1 atmosphere gauge. The samples were aged 750 hours at 120 C and 157 kV/cm (400 volts/mil). Dissipation Factor measurements were made frequently, corona measurements were made as required, and each of the samples was subjected to a breakdown test at the end of the aging period.

The ranking of tracer gases was as follows: c-C<sub>4</sub>F<sub>8</sub> (perfluorocyclobutane, freon c318) best, then CF<sub>4</sub> (freon 14), SF<sub>6</sub>, and helium. The helium did not perform well at the concentrations tested and its use would not be recommended. Small concentrations of any of the other three gases should be acceptable although the freon c-318 did perform better than the others.

No testing was done to determine the effect of evolution of the gas into potheads during low pressure operation. If the gas is permanently in the oil (by blanketing the oil in the reservoir tank), the potheads must be bled after a period of low pressure operation as is done now for nitrogen- blanketed reservoir tanks.

Several detectors were evaluated for sensitivity to the proposed tracers, portability, ruggedness (i.e. no need for frequent calibration with field handling) and simplicity of use. An Ion Track Instrument Model 56 Leakgun, which is a por-

table, self-contained electron capture detector, was chosen as the preferred instrument.

An instrument was purchased, used in the field by PTI, and presented to EPRI.

Many other potential leak location methods were evaluated both theoretically and in small experimental programs, including:

- Other Flow Direction Indicators
- Subsurface Interface Radar
- Radioactive Tracers
- Earth Electrical Resistivity
- Infrared Survey
- Microphony
- Acoustic Emission (work done by others)

In a few cases, initial results were sufficiently encouraging that larger-scale programs can probably be justified if one of the proven methods is not considered suitable in a particular application. Recommendations for further work are presented in those cases.

Hydraulic bridge and freezing methods currently in use for self contained cables can be supplemented with leak location dogs, or the dogs alone can be used on shorter feeders. Lower viscosity aromatic filling oils commonly used in self contained cables should be especially detectable by the dogs.

Tracer gases could be added to a self-contained cable but concerns about more se-

vere electrical compatibility problems and the need for the tracer to be introduced, travel to the source of the leak, permeate through the cable paper, and exit through the leak and outer sheath make the leak location dogs a far more preferable method.

Compressed gas insulated cables with SF<sub>6</sub> as the insulating gas are ideally suited to leak location with the electron capture detector.

A Leak Location Manual was prepared and is available through EPRI for utilities and others that could have a need to locate buried fluid leaks.

SECTION 1  
INTRODUCTION

1.0 INTRODUCTION

A leak of pressurizing fluid from a buried cable system is a potential problem for many utilities. When leaks have occurred in the past, it has often taken weeks to locate the leak on a ten to fifteen mile long circuit, and in a few instances it has taken several months to locate a relatively small leak. In most cases the cable circuit must be de-energized for some period of time during leak location and repair; the availability of the circuit is therefore affected by occurrence of the leak.

The environmental consequences of a major leak could be severe. The cost of oil lost plus the cost of locating and repairing a leak can be high, occasionally exceeding a hundred thousand dollars.

In recognition of the seriousness of the leak location problem, the Electric Power Research Institute solicited proposals in late 1976 for a program to investigate reliable, rapid, and accurate leak location methods. Power Technologies, Inc. was awarded the contract and work began in early 1978. The investigations described in this report were completed in early 1981.

The objective of developing a rapid, reliable, accurate leak location method was accomplished by prosecution of the following tasks, which are summarized from the project Scope of Work:

1. Review the State of the Art to uncover leak location methods tried by utilities, gas and oil pipeline companies and others. Eliminate those methods that are obviously not suitable for high voltage cable systems, and continue the evaluation of the remaining methods.
  
2. Evaluate New Methods for cable oil leak location. This task included preliminary experimental studies of methods discovered in the State of the Art review, plus several other new concepts suggested in PTI's original proposal or unearthed during execution of the project.
  
3. Evaluate System and Dielectric Compatibility to determine if those methods that interact with the cable/oil system have any deleterious effects on the long-term reliability of the systems. The major part of this task consisted of long term aging tests of cable models in the presence of candidate tracer gases.
  
4. Field Tests in a Clean Environment to evaluate the proposed leak location systems in an environment free of contaminants and distractions.
  
5. Test on a Utility System to determine the suitability of the most promising systems under utility conditions. Demonstrate the systems on an actual leak if possible.

6. Obtain a Prototype Leak Location System in a form best suited for utility use. This task included the modification of commercial instruments if required.

The Scope of Work for the project was directed to leak location only. Leak detection; i.e. determining that there is a leak, is also a serious problem for utilities but was not addressed in the leak location program.

The leak location program was primarily concerned with high pressure oil-filled pipe-type cable systems since they are most prevalent in this country and have had the most serious problems with leaks. Several of the methods that were investigated are also applicable to self-contained cable circuits, compressed-gas insulated circuits, and high pressure gas-filled circuits.



SECTION 2  
STATE OF THE ART REVIEW

2.1 OBJECTIVE

A detailed review was performed to ascertain the current procedures for locating leaks on buried cable systems, to investigate other methods that have been attempted on cable systems, and to determine the state of the art of leak location procedures for non-cable areas such as oil pipeline leak location.

It was recognized that many of the methods would not be applicable to modern cable systems; the purpose of the investigation was to provide detailed information on the theory, method of application, limitations in use, and work required to develop the system for utility use.

The review comprised discussions with more than twenty cable-using utilities, research organizations such as Bell Telephone Laboratories and the American Petroleum Institute, and manufacturers of leak detection equipment. In addition, literature searches were done through the National Technical Information Service and the Lockheed Dialog Retrieval System.

A report "Phase I Report, State of the Art Review" was issued in July 1979, and formed the basis for the experimental evaluation of the more promising leak location methods. The remainder of this chapter is summarized from that report.

## 2.2 SUMMARY

As had been anticipated, the review showed there to be two primary types of systems that should be considered for cable leak location: coarse systems to rapidly locate the leak to a manhole section length (600-1200 meters, 2000-4000 feet) in a circuit that may be 24 km (15 miles) long, and more accurate but time consuming systems to pinpoint the location of the leak.

Table 2.1 gives a summary of the methods considered for rapid determination of the general location of a leak. Table 2.2 summarizes methods considered for determining the specific location of the leak. Both types of system are discussed in more detail later in this chapter.

A few of the tabulated approaches are ones which had been pursued no further than initial thoughts by PTI and others. Most of the approaches, however, had received some experimental evaluation.

## 2.3 PRESENT METHODS OF LEAK LOCATION

Discussions with many utilities early in the project showed a definite concern about the possibility of fluid leaks although only a few utilities have experienced leaks. In many cases leak location procedures were not well defined. One utility had extensive experience in locating leaks, and had developed comprehensive procedures for locating the leak. A summary of the steps in leak location is given below.

1. Determine that a leak exists, from low pumping plant reservoir level, or too-frequent operation of a pressurizing pump.

TABLE 2.1

## STATE-OF-THE-ART-REVIEW

## RAPID DETERMINATION OF GENERAL LOCATION

Method	Resolution	Lowest Flow	Dielectric Compatibility	Physical Interference	Cost of Use	Environmental Effects	Suitable for Self-Contained GITL
FLOW DIRECTION INDICATORS							
1. Thermal Probe	Section <sup>1</sup>	20 Liter/Hr.	OK	Maybe <sup>2</sup>	Low	None	No
2. Dyes	Section <sup>1</sup>	7	Test	Maybe <sup>2</sup>	Low	None	No
3. Radioactive Isotopes	Section <sup>1</sup>	7 <sup>3</sup>	OK?	Maybe <sup>2</sup>	Med	Yes	Maybe
4. Hot or Cold Injection	Section	7	OK	No	Med	No	No
5. Totalizing Flowmeter	SSJT <sup>4</sup>	Varies <sup>5</sup>	OK	Maybe <sup>6</sup>	Med	None	No
6. Differential Pressure	Stop Joint	Low	OK	No	Med	No	Self-Contained Only

- NOTES:
1. Section length between two manholes. Adding weldolets and access pits on half and quarter points, etc. can increase resolution on new lines.
  2. Concern of damage to cable if the occupied pipe is pressure-tapped.
  3. Increased resolution could be obtained by placing probes at opposite ends of a joint casing.
  4. Semi-stop joint sections (usually 4-10 km); oil stop in the cable is needed, plus bypass piping.
  5. A function of time installed in system. Typically 2 days for a 40 liter/hr leak.
  6. Concern about large numbers of stop joints if added only for leak location.

TABLE 2.2

## STATE-OF-THE-ART-REVIEW

## B. DETERMINATION OF SPECIFIC LOCATION

Method	Resolution	Lowest Flow	Dielectric Compatibility	Physical Interference	Cost of Use	Environmental Effects	Suitable for Self-Contained GITL
PINPOINT							
1. Tracer gases	Pinpoint <sup>1</sup>	Low <sup>2</sup>	Test	Remove?	Low-Med	Maybe	Yes
2. Odorants	Pinpoint <sup>1</sup>	Low <sup>2</sup>	Test	Remove?	Low	Maybe	Yes
3. Radioactive Isotopes	Pinpoint	Low <sup>3</sup>	Test	Remove?	Med-High	Yes	Yes
4. Subsurface Radar	Pinpoint	Low	OK	OK	Med	Maybe	Maybe <sup>4</sup>
5. Trained Dogs	Pinpoint	Low	OK	No	Low	No	Yes
6. Acoustic Emission	Pinpoint	Test	OK <sup>5</sup>	Maybe	Med-High	No	Maybe
7. Dissolvable Insulation Wire <sup>6</sup>	50 Meters	Low	OK	No	Med	No	S.C.
8. Microphonics	Pinpoint	Med	OK	No	Low	No	No

- NOTES: 1. Bar-holing may be necessary. Resolution affected by other underground services - ducts, etc.  
 2. Assuming gases are pre-mixed in oil. Transit time to a leak is too long for introduction at time of leak. Addition at time of leak may be suitable if rapid circulation is possible.  
 3. Suitable only if it can be put in place by rapid circulation.  
 4. Possibly suitable for self-contained, not for GITL.  
 5. May need to add a gas to give hissing sound.  
 6. Suitable only for non-urban, new installations.

2. If the suspected leak is on one of a pair of feeders, valve off the pressurizing plant and do a comparative pressure drop to determine which feeder has the leak.
3. If the leak is sufficiently large that pressure cannot be maintained, or if the leak rate must be reduced because of environmental concerns, deenergize the feeder and lower the operating pressure to the lowest allowable level. On a feeder with no head pressure due to elevation changes, this would typically mean lowering the pressure from 15 atmospheres to 4 atmospheres.
4. Inspect the route of the feeder. Lift all feeder manhole covers and covers of adjacent manholes--e. g. sewer, distribution feeders, telephone lines.
5. Deenergize the feeder if not previously done. If the feeder is filled with a high viscosity oil, use the Con Edison-designed Thermal Probe in the center manhole, then quarter points, etc. to attempt to isolate the leak to a manhole section. The Thermal Probe has not been successful in low viscosity filling oils; generally the utility freezes the oil near the mid point, then the quarter point, etc.
6. Use boreholes, test pits and freezes as required to pinpoint the location of the leak.
7. Once the leak is found, repair it by placing a sealing clamp over the leak, then welding the clamp to give a permanent seal.

## 2.4 METHODS FOR RAPID DETERMINATION OF THE GENERAL LOCATION OF A LEAK

### 2.4.1 Thermal Probe

The Thermal Probe is the most widely used approach in the class of Flow Direction Indicators. This type of instrument is used in an attempt to determine the slow downstream flow due to the leak. The average velocity of oil due to the leak is extremely small; a 38 liter/hour (10 gallon/hour) leak will give a velocity of only 0.007 meters/minute (0.022 feet/minute) in the joint casing. This flow is well below the sensitivity of every known commercial flowmeter.

The Thermal Probe was developed by Con Edison in the mid- 1960's (1). It has a thermistor and adjacent resistor on a 9.5mm (0.375") diameter probe that is inserted via a packing gland into the vent valve on top of a joint casing. The resistor is heated slightly and the current through the thermistor is monitored. The probe is rotated 180 degrees and the reading is repeated; the higher current indicates the downstream direction.

This system was used successfully for almost ten years with standard viscosity filling oils. After newer cable systems filled with low viscosity oils were introduced, the Thermal Probe began giving false readings, and its use was therefore restricted to feeders that were still filled with higher viscosity oils.

There are of course many kinds of fluid flow meters commercially available. ASME lists seven basic types of flow meters (2): differential pressure, area, velocity, head-area, force, thermal, and other.

The Con Edison Thermal Probe is a type of Thermal meter. None of the other types, with the exception of a few in the "Other" class, has the required sensitivity. The three "Other" methods suggested by ASME which showed promise for the cable leak location program were dye injection, injection of radioactive material, and hot or cold injection.

#### 2.4.2 Dyes

Dyes have been used in the laboratory to determine local flow velocities in clear pipes. They were considered for the same purpose in the laboratory evaluation of other flow direction indicators and, as the program progressed, dyes were considered for use in the steel joint casing.

#### 2.4.3 Radioactive Tracers

Radioactive tracers have primarily been used to measure gas flow in pipes by injection of a short half-life material such as Argon 41 (half life of fifteen minutes) and sampling downstream with a scintillation counter. Sodium 24, with a half-life of fifteen hours, has been used for flow measurement in liquids.

#### 2.4.4 Hot or Cold Injection

A quantity of the material being measured (cable oil, in our case) would be heated or cooled, and injected into the pipe. A downstream probe would detect a temperature change as the heated/cooled material passed downstream. The Long Island Lighting Company has done preliminary evaluation of this method.

#### 2.4.5 Totalizing Flowmeters

The basic problem with each of the flow measuring schemes is that the presence of the cables and the very low flow rates means that the flow through a given section of the pipe could be zero or in the wrong direction depending upon time dependent flow conditions. At best the local flow rate will be very low.

Some utilities have semi-stop joints installed at a frequency of every manhole to every five manholes. The spacing is a function of elevation changes, forced cooling, and general design philosophy. The splice itself is standard, but a rubber boot is clamped to the three cables at the end of the joint casing to restrict oil flow to a small seepage. During normal operation, bypass piping

around the boot allows for oil flow; the bypass piping can be closed if required during maintenance on the cable.

Con Edison has installed totalizing flowmeters in the bypass piping upon suspicion of a leak. These meters are constant-displacement devices which are left in place for a few days and are then read. Comparison of readings among all of the meters can give an indication of which section has a leak.

There are two limitations to this method. The resolution is limited to a semi-stop section, which may be several miles long. In some trials, leaky valves in hydraulically-connected cooling oil lines have led to erroneous readings.

#### 2.4.6 Differential Pressure Measurement for Self-Contained Cables

The preceding paragraphs refer to rapid location of the general area of a leak on a pipe-type cable. A differential pressure, or hydraulic bridge, method of locating leaks on self contained cables has been in use for years (3) with good success in locating the leak within fifty meters. This system is applicable to single conductor self contained cables only. (Sectionalizing the leak by successive freezes can be used for both single conductor and three conductor self-contained cables.)

### 2.5 METHODS FOR PINPOINTING THE LEAK

#### 2.5.1 Tracer Gases

There are many gases that have a low background level in air and can be detected in small concentrations by one of several types of instruments. They could be added to the cable system, and the escaping tracer fluid sought over the length of the cable. Since this would be a time-consuming method, it would probably be preceded by use of one of the more rapid methods for general location of the leak.

Bell Telephone Companies routinely use helium or SF<sub>6</sub> for locating leaks from buried telephone cables. Leaks of SF<sub>6</sub> from station equipment such as circuit breakers are commonly found with portable halogen detectors. There is no reported experience finding the leaks through pavement, though.

The Gas Department of the Philadelphia Electric Company has injected a 10% helium-in-air mixture into a drained water pipe at two atmospheres, and located the leak through pavement using a mass spectrometer.

Con Edison has also done testing with helium and SF<sub>6</sub> in a buried oil-filled line in a non-paved area. There was good success with helium but the SF<sub>6</sub> did not appear to diffuse as readily.

Detroit Edison has successfully used the oxygen deficiency method in small bore-holes to locate leaks from nitrogen-pressurized cables.

References (4-10) describe previous use of tracer gases for leak location, or as additives to cable systems to suppress ionization.

Analysis of the possible use of tracer gases received a high priority in the leak location program. Section 4 of this report provides details of the evaluation of tracer gases.

### 2.5.2 Odorants

Odorants are in common use to odorize natural gas, which has no smell of its own. The mercaptan that is used as the foul-smelling odorant is very effective in giving an indication of a leak in a confined area such as a home, and a large gas leak in the gas main can be detected by the public. The Florida Power Corporation introduced a large quantity of mercaptan into a cable pipe prior to cable installation and successfully located a small leak(11).

Leak location dogs were used in the early 1970's to locate many leaks from buried natural gas mains in Canada; see Section 2.5.5.

The mercaptan should not be used in attempts to locate leaks from cable pipes because of possible erroneous public reaction to an apparent gas leak. PTI tried several other odorants and had success with butyl methyl sulfide, which has a pungent, skunk-like smell that is just as strong as the mercaptan but is distinctly different. No further work was done, however, because of success with other more attractive methods to pinpoint the leak.

### 2.5.3 Radioactive Isotopes

In theory, one good approach to pinpointing a leak is to add a small amount of a radioactive tracer to the cable dielectric fluid, and survey the route of the feeder to detect a higher-than-background level of radioactivity in the vicinity of the leak.

Work in Denmark in the early 1950's investigated using radon (a gas, the first by-product of radium) as a tracer to be added to the pressurizing gas in low pressure gas-filled cable (12). Ground level radioactivity was monitored with a Geiger Counter; trials with this method located a leak to within one meter.

The Central Electricity Research Laboratory, England, in an unpublished report has described the use of radioactive tracers to locate leaks from self-contained cables. The program was abandoned because of possible deleterious effects on the oil, low oil movement rate, and need to wait a significant length of time to allow the radioactivity level of the soil in the area of the leak to decay to a safe level before excavation could proceed.

Radioactive tracers are often used in power plants to trace steam lines (13-14).

PTI did further analysis of the possible use of radioactive tracers, see Section 6.5.

#### 2.5.4 Subsurface Radar

Florida Power and Light routinely uses subsurface radar to determine the location of buried distribution cables, and to map the location of cable lines and other utilities under pavement. The utility also reported that the radar equipment had picked up a leak of gasoline from a buried storage tank. Subsurface radar has been used to determine the presence and location of oil pollutants in soil and groundwater (15).

Theoretical and experimental investigations of subsurface radar for cable oil leak location were done under the present contract. See Section 6.4.

#### 2.5.5 Leak Location Dogs

It is well known that animals have a far keener sense of smell than humans. The ability of a dog to sniff an article of clothing and two days later detect the owner in a crowd of people is commonplace; this is done by the dog's detecting the unique combination of skin oils. Dogs have also been trained to detect hidden explosives and drugs with a very high success rate.

A dog was used many years ago to locate several leaks in a buried gas-pressurized radio transmission line, after a mercaptan had been added to the line (16). In the early 1970's, several trained tracking dogs were used in Canada to locate more than 150 leaks in a 150 km (93 mile) long natural gas pipeline buried as much as 4 meters (12 feet) deep under frozen earth (17). A mercaptan was present in this line as well.

Two major subcontracts were funded to develop leak location dogs for underground transmission systems; the programs are described in Section 6.3.

#### 2.5.6 Acoustic Emission

Acoustic emission techniques have been used extensively to detect faulty welds in buried pipelines; the Gas Department of the Philadelphia Electric Company has done a great deal of work in this area (18).

Acoustic emission techniques for locating leaks on buried cable pipes were investigated by two utilities during the period of performance of the leak location program. Although no reports have been published, the utilities have reported that the hoped-for emissions that would be detectable at manholes were too greatly attenuated by the damping effect of the earth.

Acoustic emission was not formally addressed under the EPRI/PTI leak location program, except to keep abreast of the progress of work being done by others.

#### 2.5.7 Dissolvable Insulation Wire

A Canadian firm markets a product called "Leak-Ex" which consists of a twisted pair of wires insulated with a material which dissolves in the presence of hydrocarbons. If there is a leak of a hydrocarbon from a traced pipe, the insulation dissolves, signalling an alarm. A simple bridge measurement is then done to determine the approximate distance from the measuring point to the location where the conductors touch.

This system was evaluated by utilities and others in the 1970's. It was found to be effective and should be considered for use on both high pressure oil filled and self-contained oil filled cable circuits, with the following conditions:

1. It can be used only on new installation, obviously.
2. The material will be dissolved by any hydrocarbon so may be suitable only for suburban locations where there is little chance of extraneous spilled hydrocarbons.

### 2.5.8 Microphonics

Leaks from buried water lines and leaks from buried natural gas lines have distinctive sounds. Sophisticated microphones with elaborate filtering equipment can detect the characteristic frequencies when placed over the buried pipes and therefore indicate the probable location of a leak (19). This method of leak location is commonly in use for locating leaks in municipal water systems; many municipalities own the necessary equipment, and there are organizations that offer leak location services for water mains. An experimental evaluation of this technique was performed and is reported in Section 6.8.

### 2.6 SUMMARY

A large number of leak locating methods exist for leaks from a variety of systems. In almost every case, the conditions of an underground cable system were sufficiently different that further evaluation needed to be done to determine if the method may be suitable for use on cable leaks.



## SECTION 3

### FLOW DIRECTION INDICATORS

#### 3.1 INTRODUCTION

A typical cable circuit is 25 km long or more; every method investigated for pinpointing a leak is time consuming and expensive so another approach must be used for a rapid indication of the general location of the leak. The only access to the cable pipe is at manholes which are spaced every 600 to 1200 meters. If the leak can be isolated to the length of pipe between manholes, then the pinpointing of the leak can be done much more efficiently.

Flow Direction Indicators which either penetrate the pipe through valving in the manholes, or attach to the outside of the pipe in manholes, can permit the isolation of a leak to a pipe section. As noted in the Introduction, the typical method of application is to determine the flow direction at the mid-point of the circuit, then at the quarter point, etc. until the leak is isolated. If the cable circuit is fed from a pumping plant at one end only, then the test is for flow versus no flow. That is, if the probe is inserted between the source and the leak, an oil flow will be found but if the probe is inserted between the leak and the far end of the circuit, there will be no flow. An indication of flow direction is still worthwhile, however, to provide verification of the reading----if the probe indicates that there is a flow, but it is away from the known direction of the leak, the reading would be suspect.

All of the direction indicators that were investigated experimentally required penetration of the pipe. Most utilities have vent valves on top of the joint

casings which are suitable for insertion of a probe with the appropriate seals and packing. For those casings with no valves, it is possible to tap the casing under pressure and by welding a weldolet with a valve. There is concern that such a procedure would introduce steel shavings and burrs into the pipe; one utility currently has a program underway to develop methods to pressure-tap the pipe while removing shavings and burrs.

### 3.2 SUMMARY

The Thermal Probe, which was developed by Con Edison in the 1960's, works adequately in higher viscosity filling oils. There was little success in modifying the probe to work well in Sun #4 and low viscosity polybutene, the two filling oils now in common use on 345 kV cable systems.

An Enhanced Oil Conductivity probe was developed; it is sensitive enough to measure the lowest flows of interest.

Local oil flows due to convection currents are a real problem. Depending upon the conditions of the line, these currents can be larger than the flow due to the leak. The most sensitive flow direction indicator may therefore give erroneous readings.

Accuracy of any flow direction indicator can be improved by inserting the probe in the cable pipe, where the flow velocity is typically four times as great as in the joint casing. This approach helps overcome the errors due to convection currents.

### 3.3 EXPERIMENTAL APPARATUS

A full-size 345 kV joint casing, with a section of line pipe on either side, was fabricated from clear acrylic tubing. Fifteen small pipe stubs with

medicine-bottle septa were placed on the casing and pipe stub to allow injection of dye with syringes and needles. A three phase 345 kV splice was built to the latest Con Edison specifications, including six aluminum spiders and fully wrapping the joint (with the exception of occasional 30 cm (12") areas to allow for oil flow through the center of the joint) with cotton and nylon tape. Donut-type current transformers were obtained from the Waltz Mill Underground Transmission Test Station to permit low voltage current to be passed through the cables.

Thermocouples were placed throughout the system and were monitored by a 30 channel Fluke temperature/millivolt recorder. The system was filled with Sun #4 oil and provisions were made to circulate oil at a rate from 0.38 liters/hour to 4560 liters/hour (0.1 to 120 gallons/hour).

Oil-soluble dye powders were mixed with Sun #4 and were injected into the joint casing as desired with 20 cm (8") No. 22 needles and 50 cc syringes. An infusion pump with flow rates from 0.07 microliters/day to 140 milliliters/minute was used when a slow, uniform injection of dye was needed.

Figure 3.1 shows the acrylic joint casing with the splice in place. The open chimneys at either end allow a uniform mixing of the added oil and also prevent the pressure in the assembly from rising high enough to damage the large-diameter tubing.

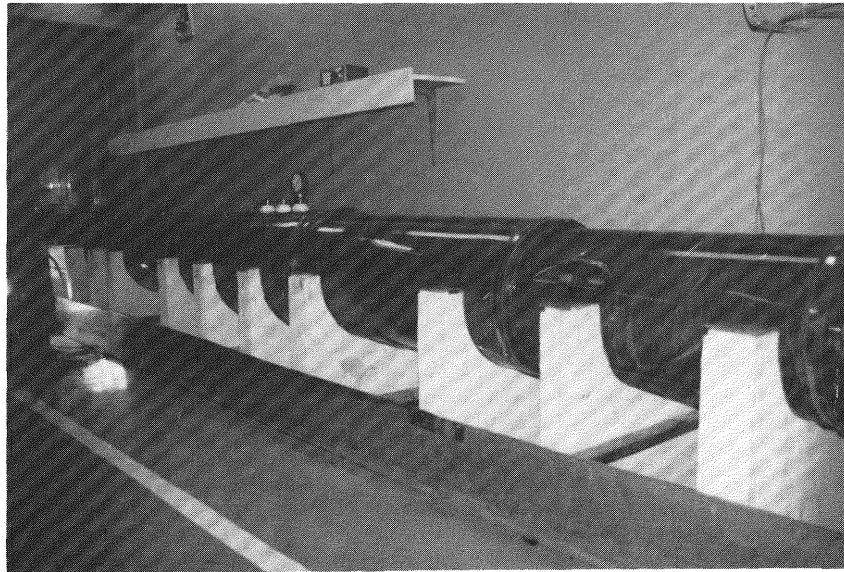
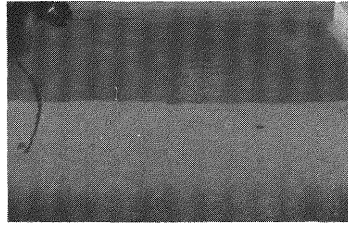


Figure 3.1. Acrylic Joint Casing.

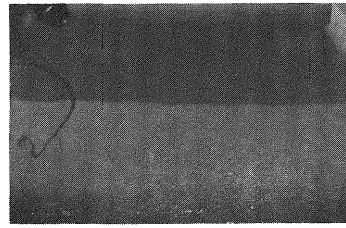
Filling and emptying of the casing proved to be cumbersome, and as described later there were problems with convective currents. A smaller section of clear acrylic tubing, 8.75 cm ID by 150 cm long (3-1/2" by 50") was therefore constructed and was used for preliminary tests with new probe designs. Flow rate was controlled by a throttling valve and could be varied from almost zero to a flow corresponding to 150 liters/hour (40 gallons/hour) in the cable pipe.

#### 3.4 SECONDARY OIL FLOWS

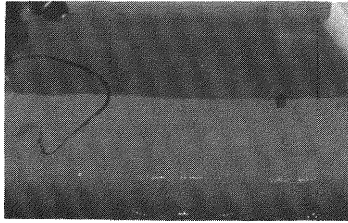
The first injections of dye into the casing showed a well-behaved parabolic flow pattern expected for laminar flow in pipes, as shown in the photographs of Figure 3.2. Subsequent testing, however, showed odd flow patterns, some with flows in the direction opposite to the leak with a magnitude three times as great as that due to the leak. This phenomenon of secondary flow had been suspected by Con Edison as the cause of erratic readings in the field. Figure 3.3 shows a typical flow pattern with secondary flow. The flow direction at the pipe is downstream to the leak, while the flow nearer the cable is upstream toward the source.



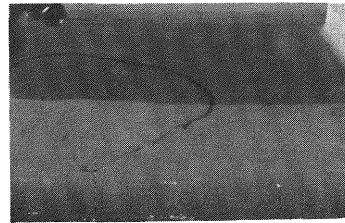
(a)



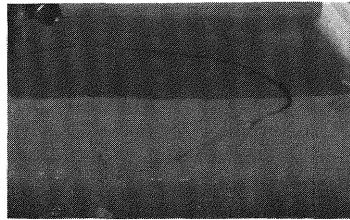
(b)



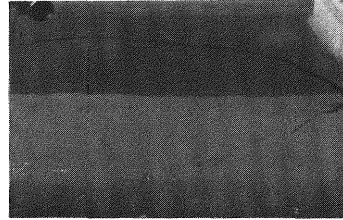
(c)



(d)



(e)



(f)

Figure 3.2. Development of Flow Patterns.

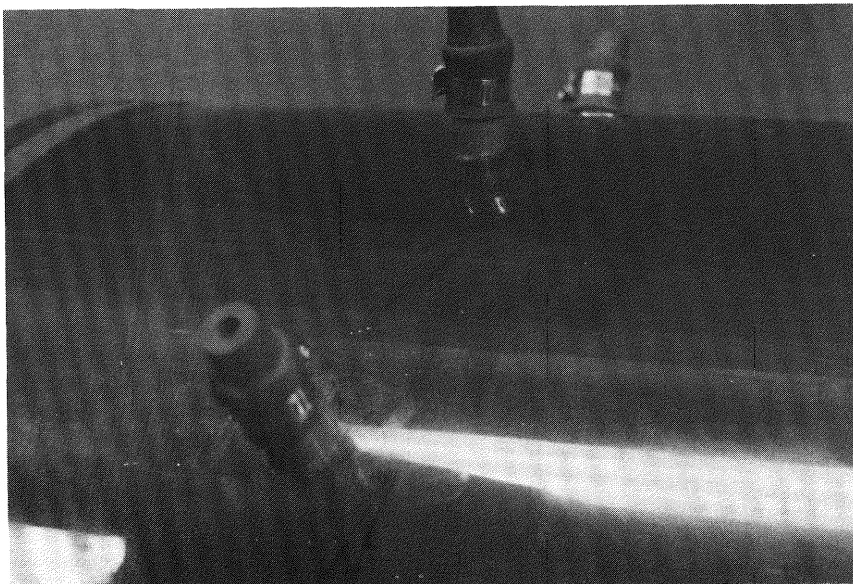


Figure 3.3. Secondary Flow Pattern.

Although not apparent from the photographs, on many occasions a dye would be added at one end of the 8.1 meter (32 foot) long assembly, and the dye streamline could be followed the full length of the assembly.

These secondary flows were investigated carefully and the following conclusions were reached:

- The secondary flows were natural convection currents due to small temperature differentials in the system. In the case of the tests at Saratoga, a 1.5 C differential existed between the two ends of the test assembly.
- As explained by Dr. L. Glicksman of MIT, consultant to the project for flow analysis, the magnitude of these currents is strongly viscosity-dependent-----for a given temperature difference, the flows could be as much as 36 times as great with low viscosity polybutene as with standard polybutene. This point explains the troubles experienced with the thermal probe as testing was done on feeders filled with the lower viscosity oil.
- There are too many variables in the field to be able to predict the value of these natural convection currents. Specifically, the thermal mass of the earth will tend to reduce temperature variations but adjacent steam mains, water lines, or distribution duct banks may still give large local temperature changes. Also, load changes on an adjacent feeder will probably induce temperature changes and hence oil flows in the circuit being monitored.
- The problem will exist with any system that monitors oil flow in a very small area. There has to be a return oil flow path; for example at Saratoga a 1 meter/hour flow may be found at the top of the acrylic casing, but a similar flow in the opposite direction would be found in the bottom of the casing. For given conditions, the direction of flow that would be measured would depend upon the point of insertion of the probe.

Note that these circulating currents are independent from those due to heat generated in the cables when carrying load. Con Edison procedures require waiting thirty-six hours after deenergizing a feeder before beginning tests with the thermal probe. Dr. Glicksman's calculations verified the need to wait that length of time.

As noted above, the circulating currents are strongly viscosity- dependent. A test was therefore done on the clear acrylic joint casing to determine the effect of injecting a slug of higher viscosity oil into the pipe. In theory, the higher viscosity oil will dampen the circulating currents and the slug will continue to move toward the leak at the bulk flow rate corresponding to the size of the leak.

A temperature difference was established end-to-end on the assembly so that strong circulating currents could be observed by injecting dye into a test port. A 19 liter (5 gallon) quantity of regular viscosity polybutene was injected into the 25.4 cm (10") pipe at one end of the casing. The entire 19 liters had been dyed so that its motion could be observed. That quantity of oil was sufficient to fill 60 cm (2') of the pipe and there was indeed a significant reduction of the circulating currents for a while. The polybutene was lighter than the Sun #4 oil that filled the casing, however, and the polybutene began to seek the top of the pipe, allowing circulating currents to be reestablished beginning at the bottom of the pipe.

If Sun XX were available (or high viscosity polybutene in a casing filled with low viscosity polybutene) and if a significant quantity of the material could be injected, it is quite possible that the circulating currents would be reduced for long enough time to allow accurate readings with a flow direction indicator.

Con Edison had constructed at its Vernon Center a full steel 345 kV joint casing with long sections of line pipe either side. Full-size cable and joints were installed in the pipe, and an accurate flow system was connected. The system was above-ground in a shed and the pipe was filled with low viscosity polybutene, the filling oil used by Con Edison for 345 kV cables. The system could be pressurized to 30 atmospheres. Con Edison kindly permitted PTI to use the casing for pre-field trials of new probe designs.

### 3.5 THERMAL PROBE

The Con Edison Thermal Probe consists of a 20 ohm resistor mounted next to a 2000 ohm thermistor. As shown in Figure 3.4, the resistor and thermistor are mounted at the end of a 8 mm (5/16") diameter brass tube approximately 43 cm (17") long.

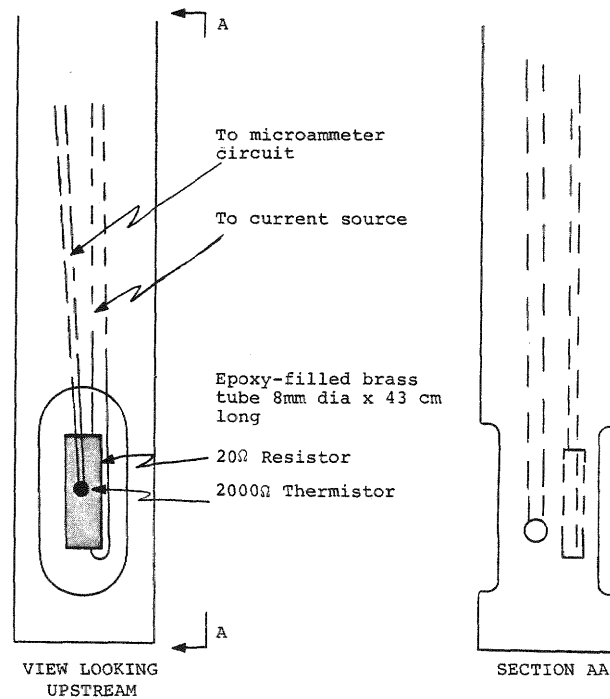


Figure 3.4. Sketch of Con Edison Thermal Probe.

All Con Edison HPOF feeder joint casings have a vent valve at the top of the center sleeve. For leak location, a second valve with appropriate packing is screwed into the vent valve and the probe is inserted through the packing. The vent valve is then opened and the probe is inserted to the desired depth in the pipe.

The resistor is energized and a microammeter in the thermistor circuit is set to zero using a balancing resistor. The probe is then turned 180 degrees and the microammeter reading is taken. If the reading is still zero, no flow is present.

If the reading is other than zero, there may be a local oil flow. The balancing of the microammeter and reversal of the probe is in effect making a bridge reading, and the sensitivity of a bridge is approached.

The probe was used with success for ten years, on cables filled with Sun #6 and regular viscosity polybutene. In the mid-1970's, as more circuits were filled with low viscosity oils as part of a forced-cooling program, erroneous readings were commonly found. Investigation of the cause of these incorrect readings was one of the tasks of the Leak Location project.

Ontario-Hydro had in the 1970's modified the Con Edison thermal probe to have four thermistors in a bridge arrangement. The resulting sensitivity is much higher than that achieved with the Con Edison probe. There have been no occasions to try the probe on an actual leak, however.

The Con Edison Construction Department provided a thermal probe for PTI's evaluation. The probe was installed in the clear acrylic joint casing and was tested over a leak rate from 10 to 400 liters/hour (2.6 to 104 gallons/hour) with the low viscosity Sun #4 oil.

The shroud at the base of the probe that protected the thermistor and resistor was found to give too high a flow impedance; dye injection showed the oil to divert around the probe. This flow diversion is shown in Figure 3.5. Removal of the shroud gave a much better flow pattern. Dye injection near the probe showed that the heated resistor caused local rising of warm oil. Testing showed there to be an optimum combination of current into the resistor versus spacing of the thermistor. The greatest sensitivity that could be achieved with the probe in Sun #4 oil corresponded to a flow of about 30 liters/hour (8 gallons/hour). A slightly higher sensitivity could be expected in low viscosity polybutene.

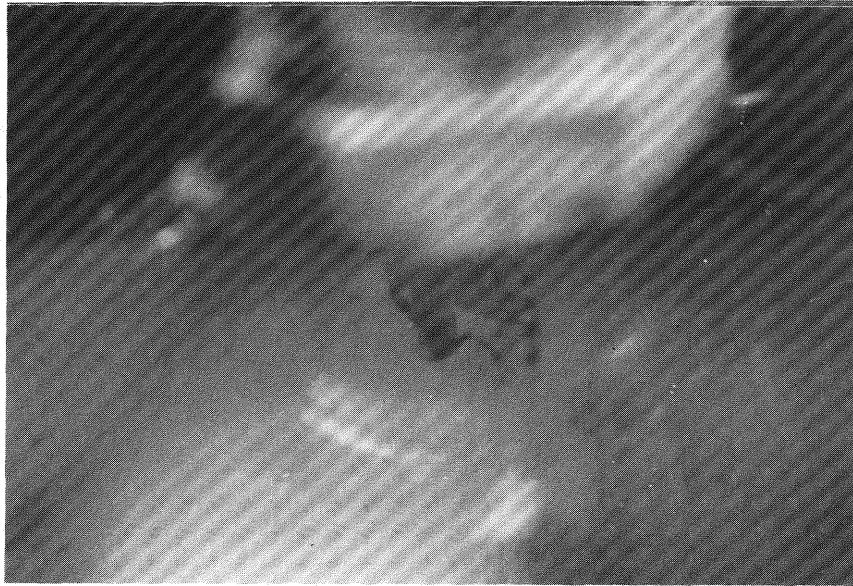


Figure 3.5. Flow Diversion Around Thermal Probe.

Several modifications were made to the thermal probe in attempts to increase its sensitivity; Figure 3.6 shows some of the design changes. An open wire-wound 20 ohm resistor (the type originally used rather than encapsulated resistors) was installed with a pair of thermistors that were connected to a bridge (Figure 3.6a). In other tests, the resistor was mounted horizontally with the two thermistors slightly above it (Figure 3.6b) to have them in the path of the rising warm oil. This latter method gave a 25% increase in sensitivity, or the ability to monitor the direction of leaks as low as 23 liters/hour (6 gallons/hour).

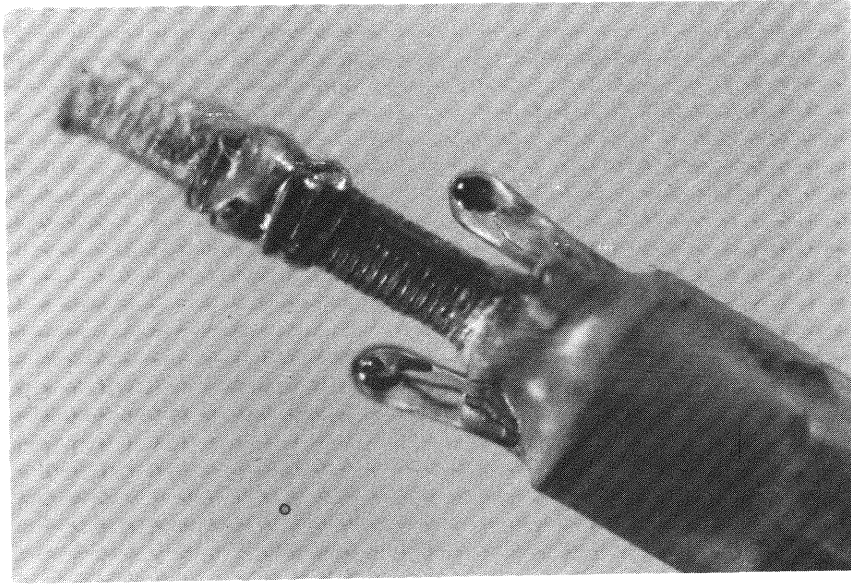


Figure 3.6A.

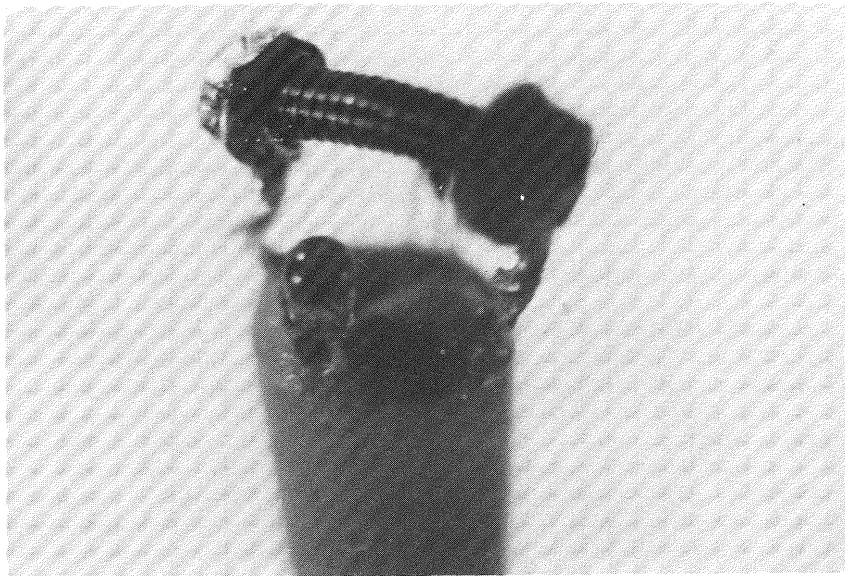


Figure 3.6B.

Modified Thermal Probes.

### 3.6 ENHANCED OIL CONDUCTIVITY PROBE

An Enhanced Conductivity Oil (ECO) probe was developed to remove some of the problems associated with heating the oil in the thermal probe, and therefore give a greater sensitivity.

Welch Chemical Company of Schenectady was able to develop an oil that has an electrical conductivity eight orders of magnitude greater than that of cable oil. Figure 3.7 gives a sketch of the probe and associated electronic equipment for monitoring movement of the high conductivity oil.

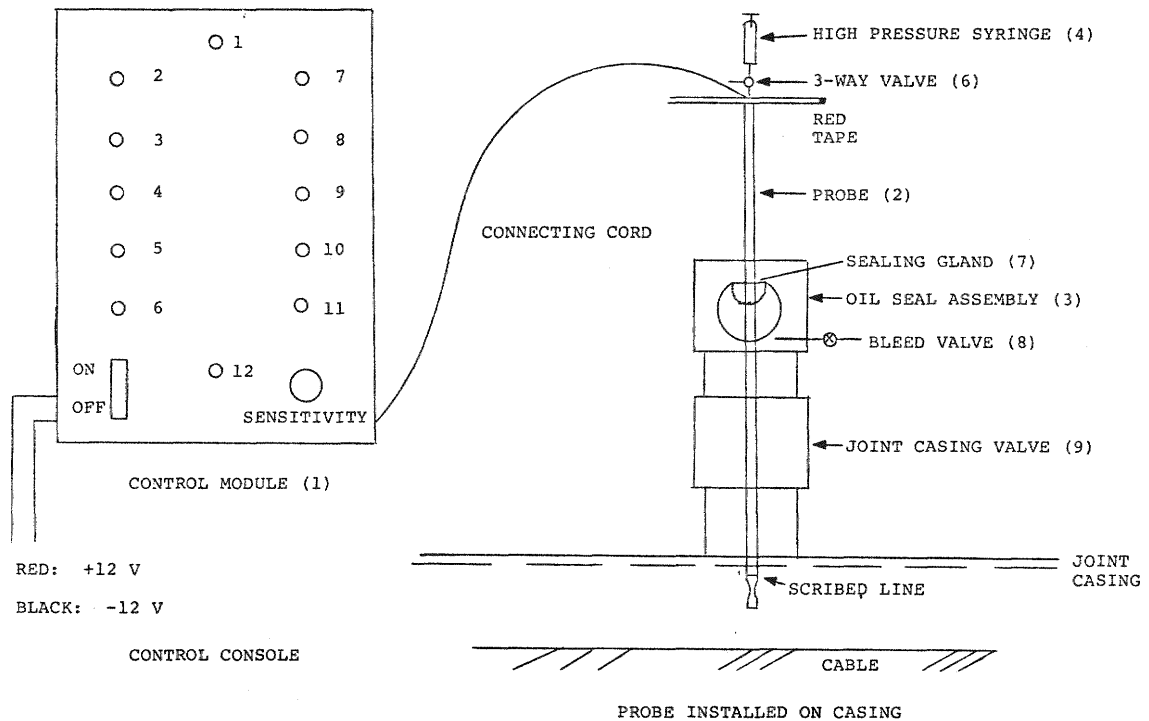


Figure 3.7. Enhanced Conductivity Oil Probe.

The probe is inserted into a valve on the cable pipe or joint casing in a manner similar to the thermal probe. A very small quantity of enhanced-conductivity oil, less than 1 cc, is injected inside the electrode array using a high-pressure syringe and needle. The oil drifts in the downstream direction and bridges a pair of electrodes; since the oil is slightly more dense than the cable oil, a high oil flow is indicated by bridging of the top set of electrodes and a low flow by bridging the bottom pair of electrodes.

The control and indication module is in essence a scanning eleven point continuity tester. Each of the eleven electrodes (five each side, plus needle) is connected to a pullup resistor, open collector demultiplexer, and input to a comparator. Each comparator output is connected to a triggered latch with appropriate sensitivity adjustments to light an LED. The twelfth position is to indicate a low resistance path between any of the eleven electrodes and the probe case which is at ground potential.

After the small amount of enhanced-conductivity oil has caused a pair of LED's to light, indicating flow direction, the bleed valve is opened and several liters of filling oil are flushed to remove all of the contaminated oil. Figure 3.8 shows the probe with its Control and indication module.

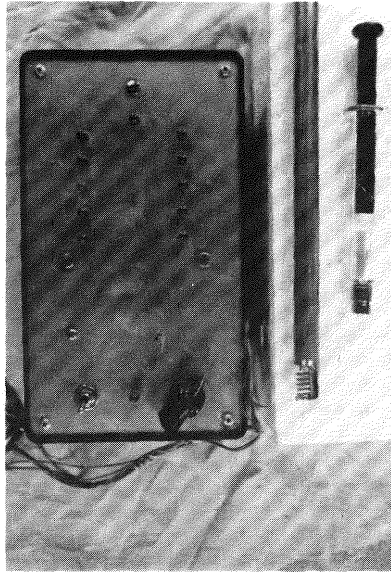


Figure 3.8. Probe with Control and Indication Module.

The ECO probe worked very well with Sun #4, down to flows corresponding to a leak of 3.8 liters/hour (one gallon per hour). The probe was taken to Con Edison's Vernon Center and applied to the full scale steel casing filled with low viscosity polybutene. There was little success in the 51 cm (20") diameter joint casing but the system worked well down to a flow of 11 liters/hour (3 gallons/hour) when installed in the 25 cm (10") diameter line pipe.

The lesser success is attributed to the lower specific gravity of the polybutene: about 0.83 compared to 0.92 for Sun #4 and 0.94 for the enhanced conductivity oil. Welch Chemicals had no success in enhancing the conductivity of polybutene so an oil blend was made between polybutene and enhanced-conductivity oil to give better flow performance but at the expense of a slightly lower sensitivity.

An Enhanced Conductivity Oil probe has been given to EPRI along with a quantity of the oil for use both with polybutene and Sun #4; design drawings have also been supplied.

### 3.7 OTHER PROBE DESIGNS TESTED

Several other designs of flow direction indicators were built and tested with varying degrees of success.

#### 3.7.1 Pendulum

One concept was to have a pendulum with the ball just slightly greater in density than the cable oil, and as large a surface area as practical. The pivot of the pendulum would offer little resistance to motion so that the ball would swing downstream with the oil flow and contact a pair of electrodes. An alternative embodiment would be to have the ball captured at its maximum swing; removal of the probe would be required to determine the flow direction.

This concept did not prove to be effective because of the very small forces developed by the moving oil.

A similar approach was to use a group of fine filaments of density just slightly greater than the oil. With the action of the moving oil, the filaments would sway downstream, anemone-like, and contact electrodes. Prototypes were made with coated nylon filaments a few microns in diameter, and graphite fibers about the same size.

The graphite fibers did indeed swing downstream at flows as low as 38 liters/hour (10 gallons/hour). The Enhanced Oil Conductivity probe was developed at about the same time, though, and gave greater sensitivity so the pendulum-type probes were not pursued further.

#### 3.7.2 Conductivity-Sensitive Filter

The sensitivity of a detector such as a ECO probe can be increased by replacing the wire electrodes with a filter material that is specific to the contaminant in the oil, then injecting the enhanced-conductivity oil slowly over a longer period

of time. Testing was done with several potential filter materials but the concept was dropped because of several problems:

- A sufficiently-fine filter element presented too great a flow restriction so that the flowing oil diverted around the filter.
- The utility advisors expressed concern with long-time injection of the contaminated oil, even though the total quantity might be small.
- The basic ECO probe proved to be sufficiently sensitive.

### 3.7.3 Distributed Thermal Probe

The thermal probe is inserted into the cable points at access valving such as on joint casings so that even if the probe worked perfectly, a leak could only be isolated to a section between two manholes.

A Distributed Thermal Probe was built and tested on the acrylic joint and cable assembly, as shown in Figure 3.9. A bare 20 ohm wire-wound resistor was epoxied to the cable shield, and 2000 ohm thermistors were epoxied either side. Leads were taken through a conax fitting to an external current source and bridge circuit.

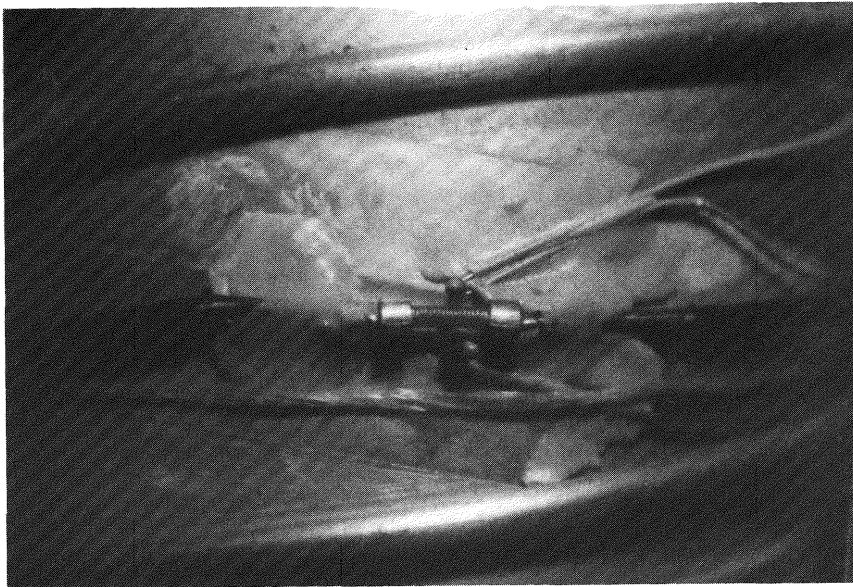


Figure 3.9. Distributed Thermal Probe.

It might be possible to attach a series of these devices to the cable shield, as thermistors were attached to the cables for the Baltimore Harbor Crossing. Upon indication of a leak, the probes would be read and if the concept worked, the leak could be quickly isolated to a short section.

As shown in the figure, the resistor/thermistors must be kept close to the cable---below the height of the skid wire---and they still would be vulnerable to damage from the skid wire from one of the other cables.

Testing showed that at the required low elevation of the device, the oil flow was so low that no readings could be obtained. The resistor/thermistors had to be elevated above the skid wires for a differential reading to be obtained. Such an approach might work in the joint casing, or just inside the line pipe where the cable positions are known. It will not work in the line pipe as originally hoped.

#### 3.7.4 Probe for Nitrogen Flow

During the course of the leak location contract, a utility had a major leak in a high pressure nitrogen filled line (operating pressure 13 atmospheres.) Such leaks are amenable of addition of a variety of tracer gases such as helium, SF<sub>6</sub>, or a freon. The line was over ten kilometers long, though, and a flow direction indicator was desired to isolate the leak to a manhole section.

A very sensitive rate-of-climb sensor had been developed for model gliders (20). The device consists of an airtight bottle with a small opening in its lid into which a pair of extremely small thermistors are inserted one behind the other. The thermistors are self-heated by passing a few milliamps through them, and they are connected to a bridge circuit. As the device is raised, atmospheric pressure is very slightly lower, air flows from the airtight bottle, the rear thermistor is cooled and the front thermistor is heated by the flowing air. Lowering the device causes the air flow to be in the other direction. An oscilloscope or microammeter in the bridge circuit gives an indication of the direction of flow.

The sensitivity of this unit was considered to be about 1.5 m/minute (5 feet/minute), compared to 3 m/minute (10 feet/minute) for sensitive commercial anemometers. One of the units was purchased and analysed. A prototype unit was made and placed into a probe of the size to fit in a vent valve on the feeder (See Figure 3.10).

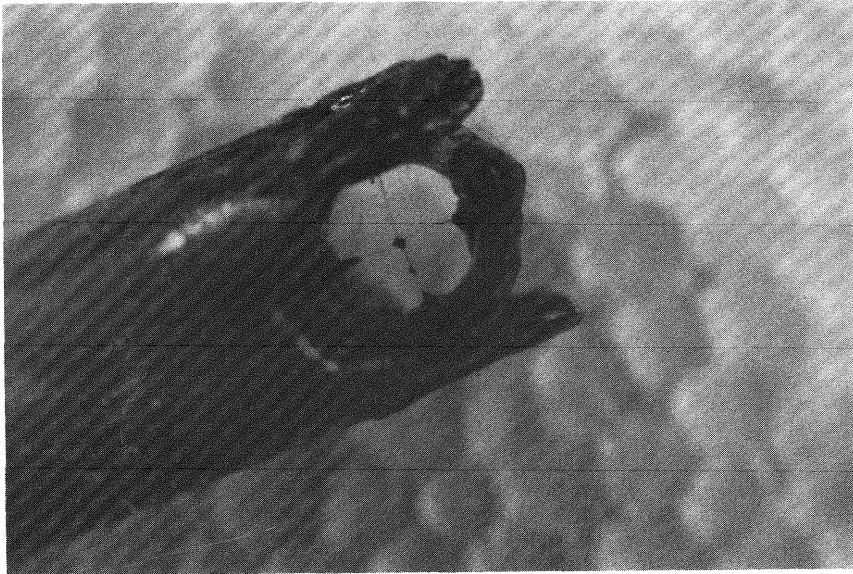


Figure 3.10. Two-Thermistor Probe for Nitrogen Flow.

The probe was tested at the Saratoga site and had a sensitivity of about 30 cm/minute (1 foot/minute). This is the approximate velocity of the nitrogen feeding the leak on the feeder, but there was no opportunity to use the probe on the utility system.

The probe was tried in cable oil and has a sensitivity about the same as the Thermal Probe. The thermistors are about 0.1 mm diameter with 0.03 mm diameter leads (5 mils and 1 mil) and are therefore very fragile.

### 3.8 POSSIBLE FUTURE WORK

The Enhanced Conductivity Oil probe is considered to be satisfactory for determining flow direction for leak rates down to about 3.8 liters/hour (one gallon/hour) which is the lowest leak of interest. The probe will accurately show the direction of any flow that is present---and as discussed earlier the flow may be in the direction opposite to the leak because of local circulating currents.

Thoughts on further work were therefore directed to methods to account for these convection currents.

### 3.8.1 Radioactive Tracer

Figure 3.11 shows a joint casing with convection currents induced by temperature differences somewhere along the cable pipe. The convection currents must integrate to zero across a cross-section of the pipe---there is no source of oil other than the pressurizing plant, and no sink other than the leak.

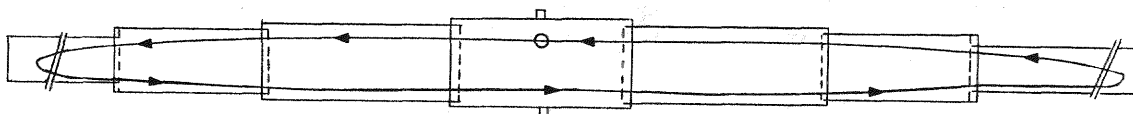


Figure 3.11. Joint Casing Showing Convection Currents

One possibility for determining the net flow is to inject a small quantity of radioactive material such as oil tagged with Sodium 24, and circulate the material between the vent and drain valves until it is thoroughly mixed at that cross section. Scintillation counters, or even sophisticated dosimeters on the line pipe at either end of the manhole can be left in place several days, then read to determine which end has a higher level of radioactivity and is therefore the direction of the leak.

This system will work for most flow conditions, but there are a few plausible conditions that may still give erroneous readings.

The approach has been reviewed by radiation physicists and appears to be technically feasible. The next step would be to conduct tests in steel pipe for a range of circulating currents and leak rates.

### 3.8.2 Borescope

The injection and monitoring of dyes in the clear acrylic joint casing was very instructive for determining the presence and magnitude of circulating currents in the oil.

If a flexible borescope with light source could be made leak-tight at 10-20 atmospheres, and if sufficient control could be obtained to have the borescope examine the full cross-section of the joint casing, we could have an effective device for determining flow in the casing.

Discussions have been held with manufacturers of borescopes. The concept appears feasible; development of the borescope would be a major undertaking, though. It may be possible to use simpler borescopes at atmospheric pressure to determine the usefulness of the device. If there is success, a high pressure, more flexible unit could be designed and built.

This device, if successful, could also be useful for investigating the cable in the joint casing to look for possible mechanical or electrical distress.

### 3.8.3 Multiple Probes

It is unlikely that at a given time circulating currents will exist in the same direction along a significant length of the feeder. If simultaneous readings could be taken for a series of probes, and the results analysed either manually or by a microprocessor, it should be possible to quickly isolate the leak to the pipe section between probes.

This could possibly be done by inserting probes at the beginning of leak location operations. Much better results could be obtained, however, by having the probes already in place and either making electrical connections external to the pipe and taking readings, or even by having the probe output wired to a central loca-

tion. The latter method has obvious advantages for speed and ease of readings, but requires the placing of control wiring in manholes which has not been too successful in the past.

If this method were adopted, the probe sensitivity would not have to be as great, since the probe would be placed in position during splicing operations and it would be possible to have several probes in a casing. A modified Thermal Probe would be ideal for this application.

## SECTION 4

### TRACER GASES

#### 4.1 INTRODUCTION

A device such as an enhanced conductivity oil probe can be used to rapidly isolate a leak to a section of cable 700 to 1500 meters (2300 to 5000 feet) long. The next step in leak location would be to pinpoint the leak. Within this shorter portion of pipe, more exacting leak location methods are feasible. As described in the State of the Art review, utilities and others have had success with the introduction of tracer gases into buried lines, then seeking the tracers with above-ground instruments. The principal areas to be covered for use of tracer gases in cable oil leak location are:

- Compatibility of the tracer with the cable system
- Ability of the tracer to permeate backfill and pavement
- Development and fabrication of suitable instrumentation for use by utility field personnel.

The tracer gas can either be added to the affected section at the time of the leak, or it can replace the nitrogen blanket.

HPOF cables typically have a blanket of dry nitrogen at 1/2 atmosphere over the oil in the pumping plant storage tank to prevent moisture and oxygen from entering the oil. Over the years the nitrogen saturates the oil to that pressure; one of the primary reasons for specifying that potheads be bled after any length of time at reduced pressure is that the nitrogen may evolve from the oil, giving a chance for electrical failure.

Replacing the nitrogen with a tracer gas has the advantage that the tracer will begin entering the earth as soon as the leak begins and by the time leak location progresses to the area of the leak, a substantial quantity of the tracer should be in the ground. As discussed later, it may take quite a few hours for the tracer to permeate through the earth and pavement --- there would be a definite advantage to having the tracer in the oil permanently.

If the tracer gas is to blanket the storage tank, it must be at least as innocuous as nitrogen, and preferably the tracer would improve the dielectric strength of the system. The compatibility testing described in Section 5 was performed to evaluate the long term effect of potential tracer gases on the cable/oil system.

The second possibility is to add the tracer to the oil once the general location of a leak is known, by injecting the tracer at an adjacent manhole. A much higher percentage of the tracer may be added, especially if the utility is prepared to flush the section of pipe, or to remove the tracer with an oil cleaning system.

There are a few disadvantages to this approach. Once the tracer reaches a leak, the utility must still wait as long as a day before a sufficiently large concentration reaches the street surface. Of more concern is the time needed for the tracer to reach the leak. At a typical leak rate of 38 liters/hour (10 gallons/hour) in a 345 kV cable system, the tracer gas could take four weeks to reach the leak if the utility simply injected the tracer at a joint and waited for it to drift toward the leak. This length of time could be reduced to a few hours if the utility were able to circulate the oil through a companion feeder or a return pipe, or if the oil could be oscillated between storage tanks at each end of the feeder. Finally, the tracer must be removed from the feeder if there is concern for long term electrical stability. Assuming that a full 800 meter (2600') pipe section is filled with the traced oil, as much as 25000 liters

(6600 gallons) of oil must be flushed. A utility would thereafter treat the oil with a vacuum treatment plant and return it to the cable pipe or a storage tank.

#### 4.2 SUMMARY

Addition of a tracer gas to the cable system, either permanently blanketing the pumping plant storage tank, or in large concentrations near the leak at the beginning of leak location operations, is a feasible method of leak location.

Based on results of electrical compatibility tests with oil/paper insulation (See Section 5) and detectability by available instruments, sulfur hexafluoride ( $SF_6$ ) is the preferred tracer. Freon 318 ( $C-C_4F_8$ ) is just as acceptable electrically but must be leaked in larger quantities before it can be detected at the earth surface.

For the  $SF_6$  tracer, a quantity of about 1 kg (2.2 pounds) should escape the pipe before leak location begins. This corresponds to 1420 liters (375 gallons) of oil saturated at 69 kPa (10 psig) if the pumping plant is blanketed with the gas, or 540 liters (150 gallons) saturated at 475 kPa (60 psig) if bulk  $SF_6$  is added to the pipe near the leak during leak location operations.

The tracer should begin to appear at the surface a few hours from the time it exits the pipe. A period of eight hours is recommended to insure sufficient quantity of the tracer for detection at street level.

It will generally not be possible to simply patrol the street surface to detect the tracer. Small boreholes, approximately 2 cm diameter by 15 cm deep (3/4" by 6") spaced 3 meters (10') apart are recommended. The simple expedient of placing traffic cones over the route of the feeder, at 3 meter maximum spacing, and sniffing the air inside the cones after they have been in place a half-hour or more, should also be effective.

Several leak detection instruments were evaluated, and an Ion Track Instruments Model 56 Leakgun was selected as being most suitable for field detection of tracer gases. The instrument employs an electron capture detector and has a sensitivity of 0.1 part per million for SF<sub>6</sub> in air. A unit was obtained, fitted with the necessary accessories for field use by utility personnel, used by PTI for several series of tests, and presented to EPRI.

#### 4.3 DIFFUSION/ATTENUATION THROUGH THE SOIL

Tests were done by Rensselaer Polytechnic Institute (RPI) to determine the diffusion rate of tracer gases through cable backfill, and to determine the degree of adsorption of the tracer by backfill material. These data were necessary to allow calculation of the length of time that must be waited before beginning leak location operations, and to permit calculation of the amount of tracer that must be added.

##### 4.3.1 Experimental Apparatus

The necessary instrumentation and gas-handling equipment was available in the RPI laboratories so most of the testing was done there. PTI therefore fabricated six test pipes, each 10 cm diameter by 122 cm high (4" by 48") as shown in Figure 4.1. Figure 4.2 is a photograph of several of the piping assemblies with gas handling equipment at RPI; the figure also shows removal of a gas sample via a syringe and needle penetrating a septum.

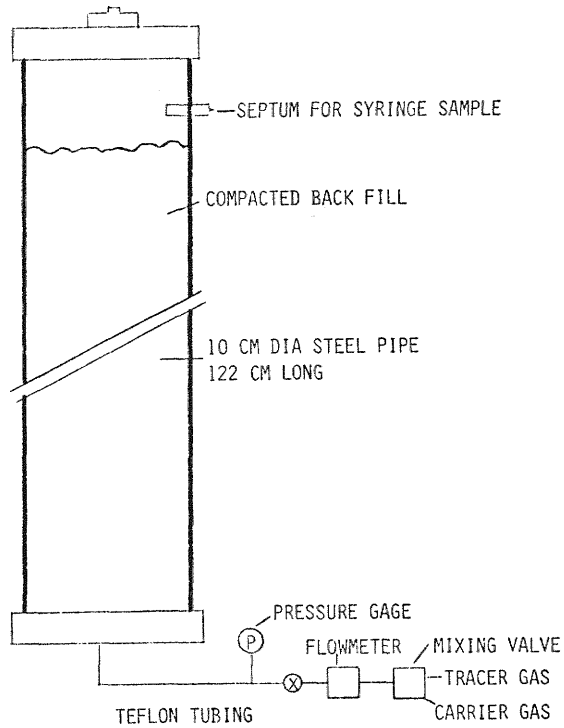


Figure 4.1. Test Pipes for Diffusion Measurements.

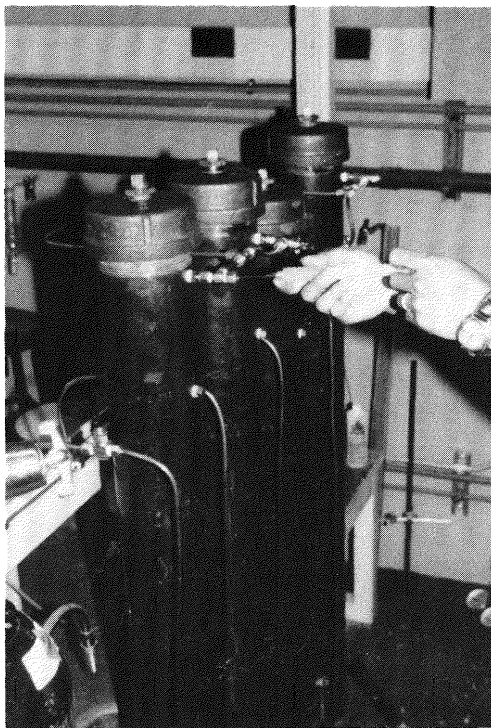


Figure 4.2. Photograph of Test Pipes.

A large quantity of controlled backfill had been ordered to Con Edison specifications, to be used for these tests plus other tests at the Saratoga Site. A portion of the backfill was dried at 120 C for twelve hours, and was packed in the steel pipes to a density of about 1220 kg/m<sup>3</sup> (120 lb/ft<sup>3</sup>.) The pipes were taken to RPI where dried tracer gases in varying concentrations were added to the bottom of the pipe at varying pressures. Syringe samples were taken from a septum in an open space at the top of the pipe, at specified times after injection of the tracer began. The samples from the syringe were injected into a Carle gas chromatograph with thermal conductivity meter, and the quantity of the tracer was measured. Figure 4.3 shows the insertion of the syringe into the sampling port of the chromatograph.

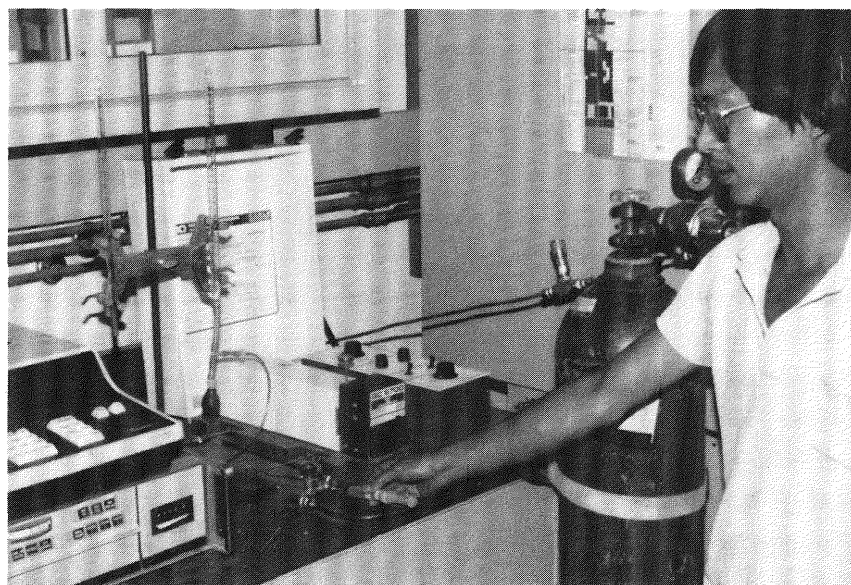


Figure 4.3. Insertion of Syringe Sample into Chromatograph.

#### 4.3.2 Results

Although care had been taken to compact the backfill in each of the pipes uniformly to the same density, initial pressure drop tests by RPI showed there to be a significant difference---at a pressure differential of 69 kPa (10 lb/in<sup>2</sup>)

across the tube, the resulting flow rate with nitrogen varied from 1 to 2.7 l/min for the four pipes that were used for most of the tests. It is speculated that there was channeling in the pipes and uniform flows may not have been achieved through each cross section at the higher pressures. The effect on diffusion flow through the pipes should be smaller. Since the program was concerned primarily with the comparison among the candidate tracers, the results were analyzed for each gas through the same tube, or between two tubes that had the same pressure drop characteristics.

The test procedure was to introduce the tracer gas to the bottom of the pipe at the desired pressure, and take frequent syringe samples from the septum at the top. Figure 4.4 shows typical results, for 256 ppm SF<sub>6</sub> in nitrogen at a pressure of 69 kPa (10 lb/in<sup>2</sup>).

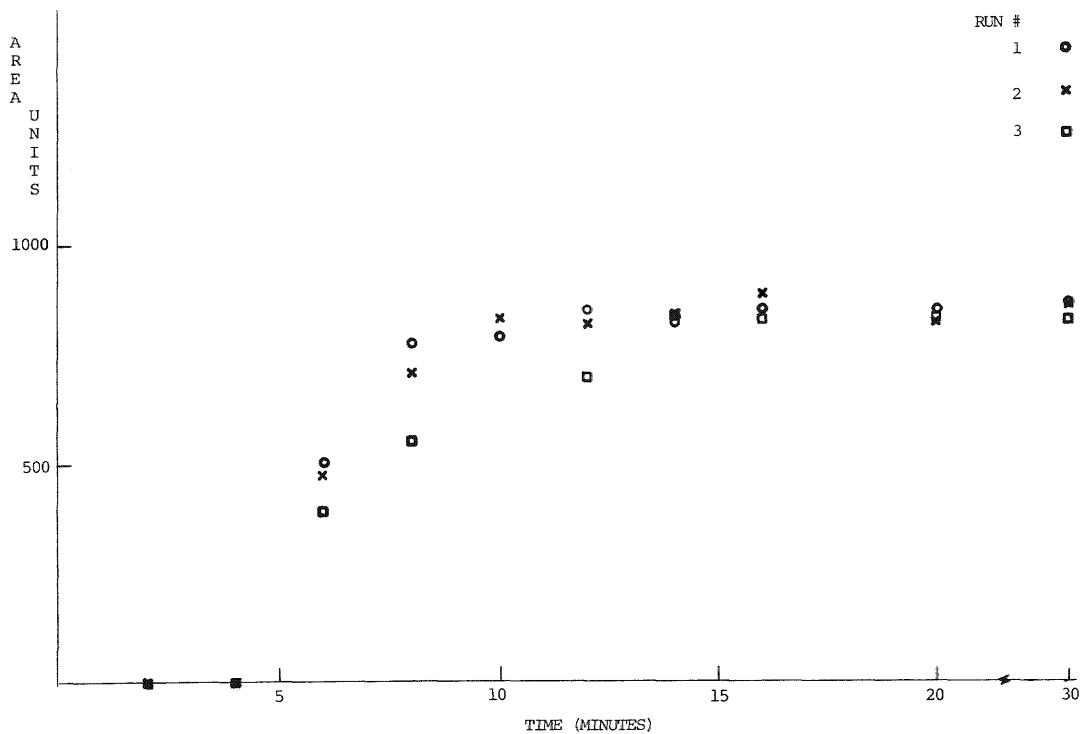


Figure 4.4. Typical Results, Diffusion/Attenuation Tests.

Two numbers are of principal importance; the breakthrough time, or time at which the tracer first appears at the sampling point (about 4.5 minutes on Figure 4.4) and the time for saturation, when the outlet density equals the inlet density of the tracer (about 12 minutes on Figure 4.4). Also of interest is the breakthrough volume---that is, the volume of gas displaced from the tube from time zero to the breakthrough time. For example, in the typical test from which Figure 4.4 results were obtained, the breakthrough volume was 4.3 liters. A porosity of 0.4 to 0.5 is generally assumed for dry compacted sand (that is, even though the sand appears to be completely compacted, there is still 40 to 50% free air space). The displacing of 4.3 liters therefore shows that the entire free volume of air had to be displaced before the tracer gas began to appear at the surface.

Results for the tests at RPI are summarized in Table 4.1. Table 4.2 gives a comparison of the four tracer gases tested sequentially (with purging between tests) in the same tube.

TABLE 4.1  
SUMMARY OF DIFFUSION RESULTS

Tracer	Flow l/min	Breakthrough Minutes	Saturation Minutes	Breakthrough Volume, liters
SF6	1.1	4-5	16	4.95
SF6	0.03	100	>170	3.0
SF6 <sup>1</sup>	1.1	3	12	3.3
SF6 <sup>1</sup>	0.03	85	>100	2.55
SF6 <sup>2</sup>	1.6	<2	4	3.2
He	1.0	4	8	4.0
He	0.03	60	120	1.8
He <sup>2</sup>	1.7	1	5	1.8
He <sup>2</sup>	0.075	3	10	0.22
CF4	2.87	1	3-4	2.87
CF4	0.035	>60	>140	2.1
C4F8	1.1	10-12	30	12.1
C4F8	0.035	>60	125	2.1

Notes:

- 1 6 percent moisture was added to the tubes used for earlier tests.
- 2 The tubes were filled with sand having 6 percent moisture. Better compaction was achieved than for dry-packed tubes.

TABLE 4.2  
COMPARISON OF DIFFERENT TRACERS IN SAME TUBE

	- He -		- SF <sub>6</sub> -		- CF <sub>4</sub> -	- (CF <sub>2</sub> ) <sub>4</sub> -	
Flow	1.0 <sup>1</sup>	0.03	1.1	0.03	- 0.035	1.1	0.035
BT	4	60	4-5	100	- 60	10-12	>60
ST	8	120	16	170	- 140	30	125
BTV	4	1.8	4.95	3.0	- 2.1	12.1	2.1

<sup>1</sup>Tube #6

#### 4.3.3 Analysis

Review of the results shown in Tables 4.1 and 4.2 yields the following observations:

- The ranking of the four tracer gases for time for diffusion through the sand in the pipe (flow rates of about 35 milliliters/minute) or bulk flow (flow about one liter/minute) is as follows: helium fastest, then CF<sub>4</sub>, SF<sub>6</sub>, and C<sub>4</sub>F<sub>8</sub>. This ranking is the same as the molecular weights for the gases, as might be expected.
- More than an hour is required for SF<sub>6</sub> and C<sub>4</sub>F<sub>8</sub> to diffuse through the controlled backfill in the pipe. This is in line with the results in the field at Saratoga, described in Section 4.4.
- The presence of moisture in the backfill speeds the time for breakthrough and saturation. The 40-50% void space in the backfill is partially filled with water vapor so that less tracer gas is needed to fill the remaining voids. The generally lower breakthrough volume for samples with a 6% moisture content tends to confirm this observation.

Appendix A presents a model and sample calculations for diffusion of tracer gases through soil. This model will be useful for other organizations doing research in gas diffusion through backfill. A utility engaged in leak location operations will be unlikely to have available the soil characteristics necessary to perform the required calculations; it is recommended that the tracer concentrations recommended in Section 4.7 be followed by utilities.

RPI conducted a series of tests to attempt to determine the effect of asphalt and concrete on the diffusion and attenuation of the tracer gases.

PTI retrieved two of the test pipes after completion of planned tests at RPI and placed 15 cm (6") plugs of asphalt and concrete in the top of the pipes. The interface between the paving material and the pipe was coated liberally with silicone seal in an attempt to eliminate gas passage at that point. The two samples were then returned to RPI for a series of tests such as those described above.

Tests were done with helium and SF<sub>6</sub>. At low flows corresponding to diffusion of the tracer, the results were comparable to the results obtained on samples without the paving material.

At bulk flows of about one liter per minute, however, the breakthrough time was shorter than obtained without the concrete or asphalt. It is possible that the higher pressure necessary to give the 1 liter/minute flow caused additional channeling and therefore faster travel times.

#### 4.4 TESTS WITH BURIED LEAKS AT SARATOGA TEST SITE

##### 4.4.1 Test Area

Three sets of buried leaks were installed at the Saratoga Site primarily for tracer gas tests, although each of the leak areas was used for other tests as well.

The first leak consisted of a 16.7 m (50 foot) long section of concentric pipes, 12.7 cm (5") and 5.1 cm (2") diameter, buried 1.2 m (4') deep, with half of the length paved. Leaks controlled by solenoid valves were placed in the outer pipe at the center of each half section as shown in Figure 4.5. The inner pipe had

diffusion ports drilled at one end to permit rapid circulation of oil for mixing of tracer materials.

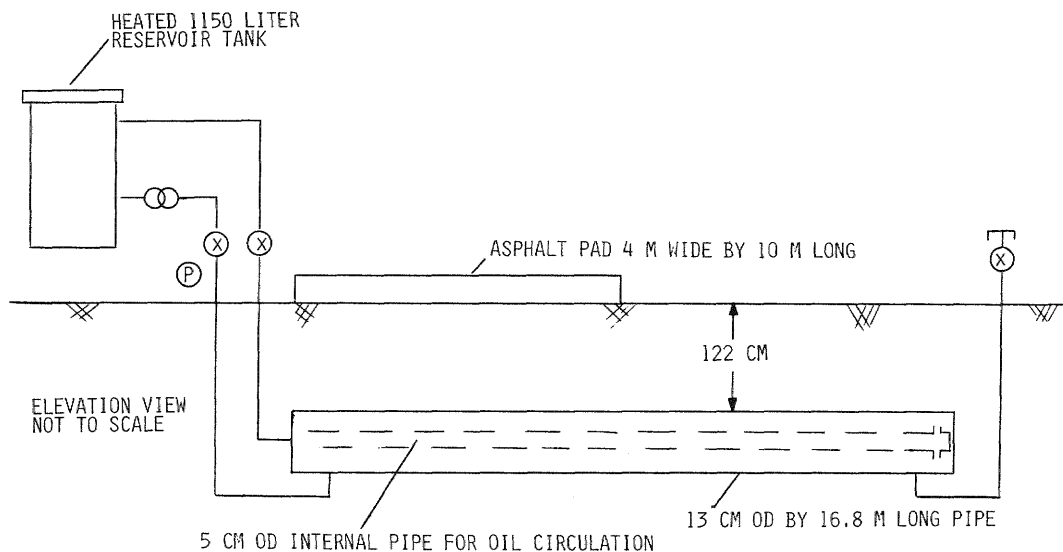


Figure 4.5. Leak #1, Solenoid-Valve Controlled.

The second leak consisted of a probe driven 3.4 m (11') under an existing black-top road, at a depth of 1.2 m (4'). (See Figure 4.6) The leak was formed by a small hole drilled near the end of the probe. Control of the leak was by means of an above-ground valve about 6.2 m (20') away from the leak. The purpose of this leak was to investigate the diffusion of the tracers through paving material that had been in place many years, in contrast to Leak #1 which was covered with newly-placed asphalt.

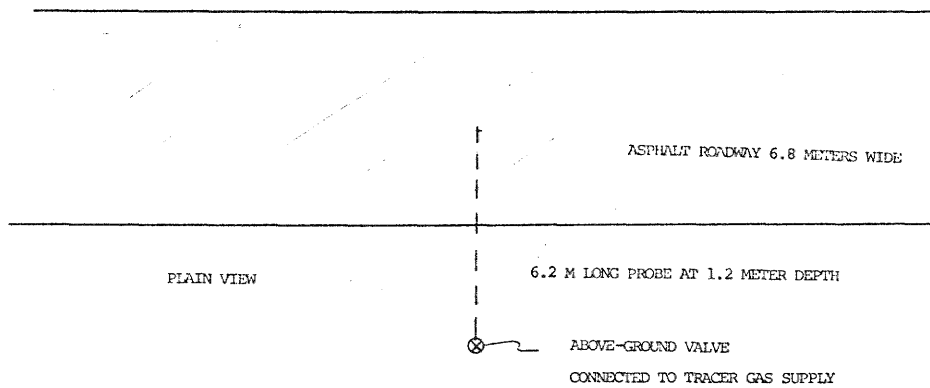


Figure 4.6. Leak #2, Under Existing Asphalt Road.

The third set of leaks consisted of four pipes, each 9.8 m (32') long connected to a common manifold as shown in Figure 4.7, and with a leak in the center of the pipe run. Individual leaks were pressurized as desired from the manifold connection. The pipes were buried at a depth of 1.2 m (4') with Controlled Backfill for 0.6 m (2') and native soil for the remaining 0.6 m. There was no pavement over these leaks.

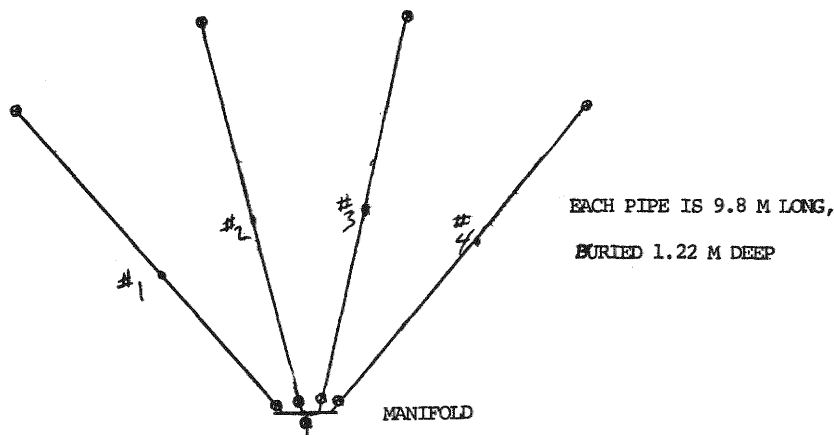


Figure 4.7. Leak #3, Four Leaks on Common Manifold.

#### 4.4.2 Tests with Tracer Gases at Saratoga

Ion Track Instruments (ITI) kindly loaned PTI the use of a Leakmeter II Electron Capture Detector (See Section 4.5). This instrument has a sensitivity of 0.01 parts per million for  $SF_6$ , and lesser sensitivities for the two other halogenated tracers,  $C_4F_8$  and  $CF_4$ . The Leakmeter II was used to generate good basic data on preferred detection methods, diffusion times, and area of diffusion of tracer gases from buried leaks.

Figure 4.8 shows the Leakmeter II.

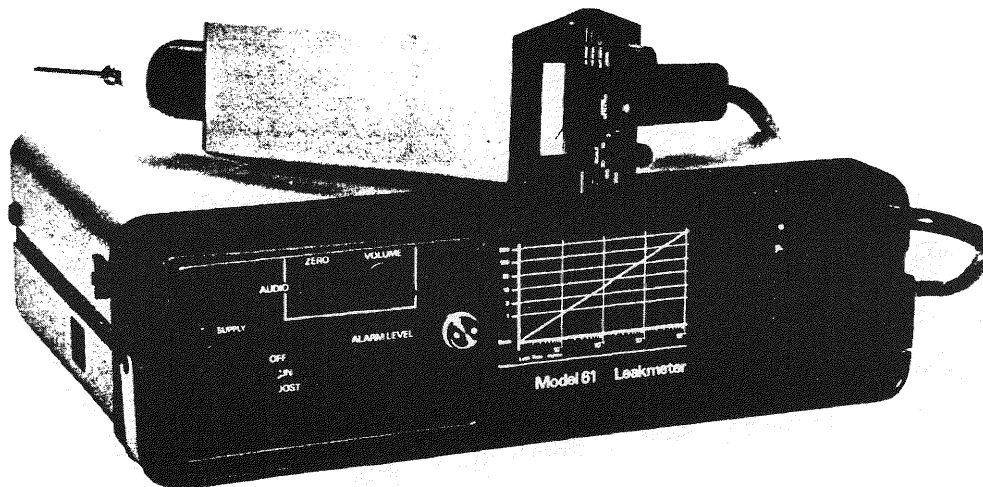


Figure 4.8. Leakmeter II.

#### Leak #1

A tank containing 0.256%  $SF_6$  in nitrogen was connected to the probe and a volume of 350 liters (12.25  $ft^3$ ) at standard temperature and pressure (STP) was injected at 6.9 kPa (1  $lb/in^2$ ) until a trace of  $SF_6$  appeared in a borehole at the asphalt surface---which took two hours. The tracer gas supply was then shut off. Of the 350 liters of gas mixture, 0.8 liters (0.03  $ft^3$ ) was  $SF_6$ , for a weight of  $SF_6$  of 0.17 grams (0.0004 lb). The concentration of  $SF_6$  was monitored at small boreholes 2 cm diameter by 10 cm deep (3/4" by 4") placed in the asphalt at 0.9 m

(3') spacing from the leak. In addition, traffic cones were placed on the asphalt surface in the vicinity of the leak. The traffic cones were standard 0.6 m (2') high hollow rubber cones that had the rubber feet removed so the cones would sit tightly on the asphalt surface.

The peak concentration was in Borehole #1 (directly over the leak) at 39 ppm after 25 hours, and the concentration stayed in the range 30-29 ppm until about 75 hours when it began to drop.

The concentration in boreholes 2 meters (6') away peaked after 45 hours, at a concentration of 14 ppm. The farthest reading was 0.01 ppm at a distance of 6 meters (18') after 75 hours.

Figure 4.9 shows the profile of SF<sub>6</sub> concentrations at 2.25 hours, 25 hours, 66 hours, and 163 hours. Note that the gas was turned off at two hours after a small quantity was leaked. In an actual leak, both the duration and quantity of the tracer would be far larger.

The concentration in the traffic cone is not shown on the Figure. The level of SF<sub>6</sub> in the cone reached about 2 ppm, or one twentieth that of the boreholes. The 2 ppm level was readily detectable with the instrument, however, and the ability to search for a leak without having to borehole would be a definite advantage to a utility.

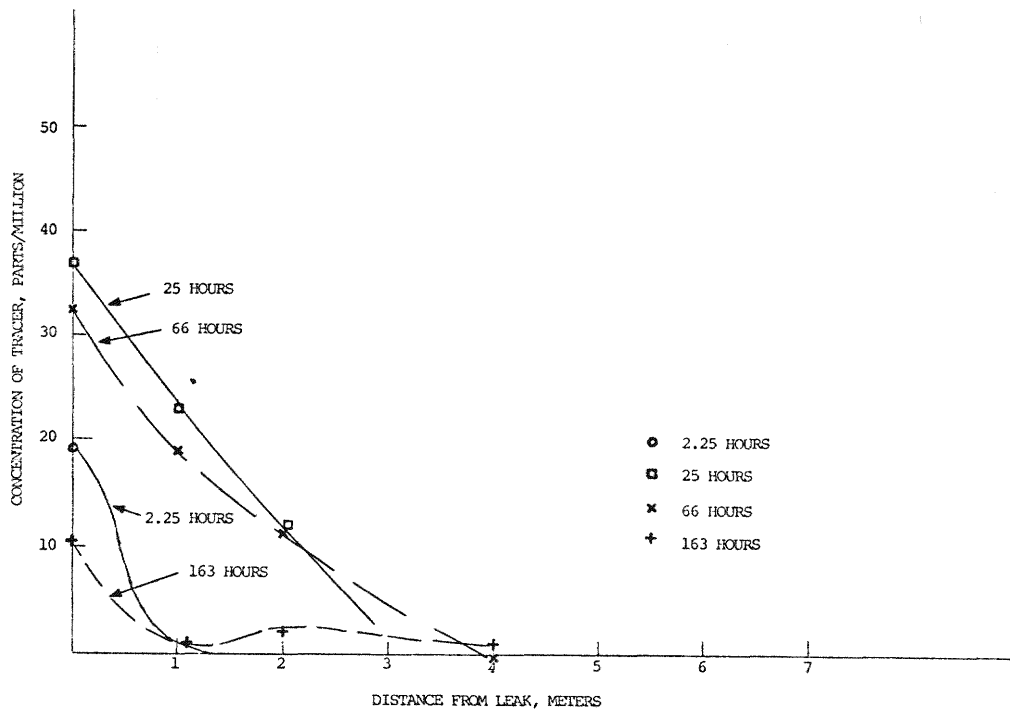


Figure 4.9. Leak #1, Tracer Concentration Vs. Time and Distance.

### Leak #2

The same 0.256% SF<sub>6</sub> in nitrogen mixture was placed in one of the buried leaks in the group of four leaks sketched in Figure 4.7. A volume of 80 liters (3 ft<sup>3</sup>) of the mixture was placed in the ground at a pressure of less than 6.9 kPa (1 lb/in<sup>2</sup>) until a trace of SF<sub>6</sub> appeared at the surface. The time to reach the surface was about 2 hours which is the same as for the leak under asphalt. The leak rate for this second leak was one quarter as large, however, so that only 25% as much SF<sub>6</sub> was leaked before it was detected.

The concentration of the tracer peaked after five hours and began dropping after about 20 hours. In this case, the cone gave a higher reading than the boreholes---16 ppm versus 5.7 ppm. This was expected, since the tracer had a relatively free path to the surface and the cone acted as a concentrator by in-

creasing the area of the earth that was sampled. This is in contrast to the borehole in pavement where the hole formed the easiest access to the surface.

Figure 4.10 shows the tracer concentrations in the boreholes after 4.1, 27.4 and 69.7 hours. For this slug of tracer, the reading directly over the leak began to decrease after about 20 hours while that in a borehole a meter away peaked at about 27 hours then began to decrease. After about 70 hours the concentration was a uniformly low, but still detectable level of about one part per million.

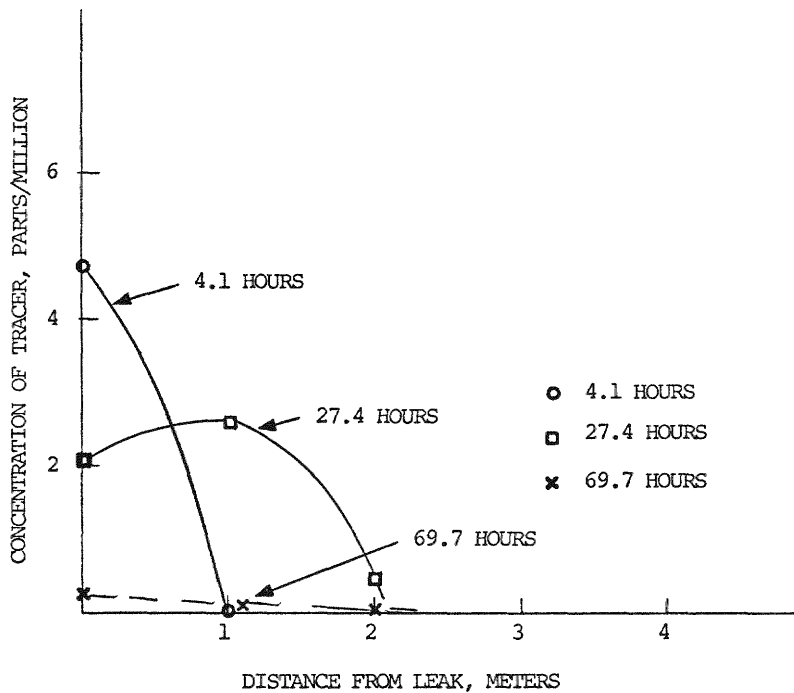


Figure 4.10. Leak #2, Tracer Concentration Vs. Time and Distance.

### Leak #3

The third leak was placed in one of the other pipes connected to the manifold sketched in Figure 4.7. Pure SF<sub>6</sub> had been bubbled through 23 liters (6 gallons) of Sun #4 oil at 69 kPa (10 lb/in<sup>2</sup>) which gave a dissolved quantity of 16 grams (0.6 ounces) of SF<sub>6</sub>. The oil was then forced through the buried leak at a pres-

sure of 69 kPa, and care was taken to shut off the supply before any gas exited the leak to insure that the only SF<sub>6</sub> present evolved from the saturated oil.

Figure 4.11 shows the concentration of the tracer in boreholes as a function of time from the injection of the oil.

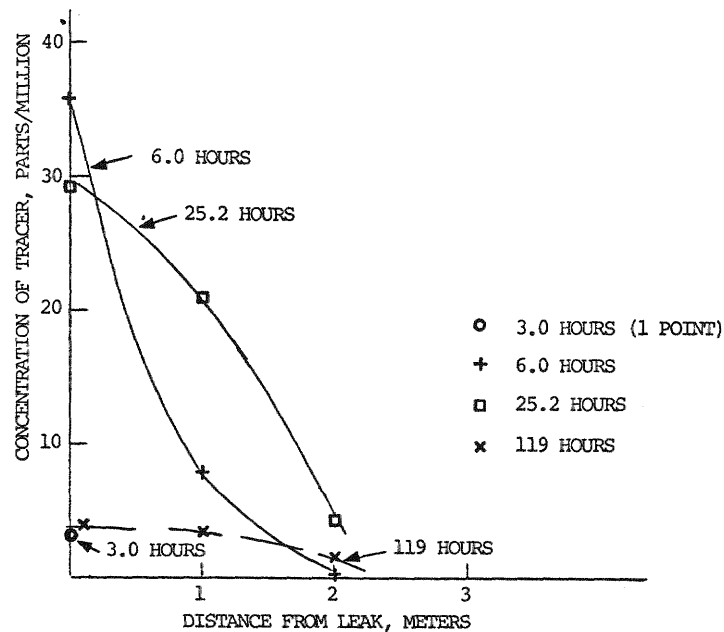


Figure 4.11. Leak #3, Tracer Concentration Vs. Time and Distance.

The tracer reached the boreholes after about three hours, at a concentration of more than three parts per million. The concentration in the borehole over the leak, (as well as a traffic cone adjacent to that borehole) did not peak until about 28 hours and the level remained high until more than 119 hours. The high levels of SF<sub>6</sub> for long periods of time after injection of the oil indicate that the SF<sub>6</sub> is evolving slowly from the oil, and that SF<sub>6</sub> must then diffuse to the surface.

Although no testing was done for oil migration through the soil during the present tests, earlier analysis had showed the oil to travel almost straight downward in the sandy Saratoga soil. An actual leak in a utility, in which a far larger amount of oil is leaked, and which would be expected to spread over a greater distance, should provide much higher surface-level concentrations of SF<sub>6</sub>.

For each of the three tests described above, careful measurements were made of the air at the ground surface in the hope that SF<sub>6</sub> could be detected. Such detection was not possible even with the highly sensitive Leakmeter II; it appears that the utility will have to borehole or to place a series of traffic cones over the feeder route in the area where the leak is suspected.

Note that the traffic cones would also be an effective collector for oil vapors to assist the leak location dogs in a search, and would probably remove many of the effects of ground-level winds.

#### 4.5 INSTRUMENTATION FOR DETECTION OF TRACER GASES

A detailed analysis was done of the instruments that would be preferred for field use to detect one of the candidate tracer gases.

The preferred detector for helium is a mass spectrometer, and portable instruments are available that are sufficiently sensitive. No further consideration was given to that type of instrument, however, after review of the relatively poor results of electrical aging tests on samples having helium tracer.

Several types of instruments are used commercially to detect halogenated gases; some of the instruments are small enough to be carried in a shirt pocket and have a sensitivity in the order of tens of parts per million. A sensitivity of more than one part per million is required for tracer gas location through soil and

pavement. There are many types of laboratory instruments that achieve this sensitivity, and it is possible to take gas samples in the field, take them to the laboratory, and have the samples analyzed for presence of the tracer. This would be cumbersome and time-consuming, however, and the investigations were therefore limited to instruments that could sample air in the streets and give an instantaneous reading of presence of the tracer.

The electron capture detector is the preferred instrument for halogenated gases such as the  $\text{SF}_6$ ,  $\text{C}_2\text{F}_6$ , and  $\text{CF}_4$  that were investigated in this program. In an electron capture detector, a radioactive source securely contained in a detector cell generates a supply of electrons. The electrons are generated from a supply of pure argon gas. The argon also acts as a carrier for the sampled gas. If a halogenated (electron-capturing) gas is present in the sample, as the argon carries that gas through the detector some of the free electrons are captured and the current through the detector decreases. The degree of current reduction is a function of the amount of electron-capturing gas present.

Sophisticated laboratory equipment exists combining gas chromatography with an electron capture detector. A gas sample is injected into the chromatograph, separation of the components of the sample takes place, the component with the residence time of interest passes into the detector, and the presence and quantity of the gas are determined.

The need for a radioactive source has limited such instruments to laboratory use in the past; permits had to be obtained and annual tests had to be performed to insure there was no radiation leakage. In the last several years new radiation sources and more sophisticated electronic circuits have been developed to a point where the only requirement is for the instrument manufacturer to register the source; the user has no need to obtain a permit or have a licensed operator.

Two firms now manufacture portable electron capture detectors. Both were investigated, and Ion Track Instruments of Burlington, Mass. was determined to have instruments better suited to utility use.

ITI loaned PTI a Leakmeter II for trials at Saratoga. This instrument is shown in Figure 4.8. The radioactive material is Nickel 63, at a level of 10 millicuries. Argon is the carrier gas; sampling is done by a small air pump contained in the hand-held unit, and a portion of the sampled stream is carried through the detector by the argon. The detector itself is kept at 45 C by a heater element and controls. The hand-held unit is connected to a console by an umbilical cord. The console contains a small cylinder of Argon, a battery for field operation, controls and other electrical and gas circuitry. Sensitivity is better than 0.01 parts per million for SF<sub>6</sub> in air. Sensitivity for c-C<sub>4</sub>F<sub>8</sub> is about one seventeenth as great, and sensitivity for CF<sub>4</sub> is several orders of magnitude less.

The Leakmeter II was used for several tests at Saratoga for obtaining basic data on time for tracer to reach the earth surface, and quantity of tracer present as a function of distance from the leak. The level of tracer in the boreholes and traffic cones was sufficiently high to permit use of a less sophisticated instrument, however, even for the small amount of SF<sub>6</sub> that had been leaked. In addition, the Leakmeter II was judged to be somewhat sensitive for use by utility mechanics.

The Leakmeter II was therefore returned to ITI and a Model 56 Leakgun was obtained. This unit had been developed primarily for detection of buried leaks, and has had a long history of successful use by telephone companies in searching for leaks in buried cables traced with SF<sub>6</sub> (but there had been no reported use of the unit over pavement). The unit is provided in a carrying case with several

accessories that are needed for probing boreholes. Figure 4.12 shows the unit and its standard accessories in its carrying case.

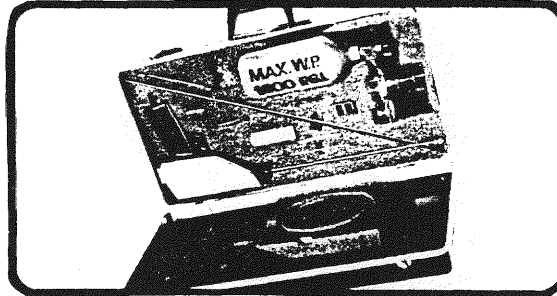


Figure 4.12. Ion Track Instruments Model 56 Leakgun.

The unit employs the venturi action of the argon carrier gas flowing through the detector to pull in the gas being sampled. A thin membrane is placed over the probe tip; that membrane keeps contaminants out of the probe and it is selective to  $SF_6$  so it tends to concentrate the amount of tracer that reaches the detector. Sensitivity is 0.1 parts per million, which is adequate for cable oil leak location under city streets. The detector is not maintained at constant temperature and the four sensitivity scales are not calibrated in terms of parts per million as is the Leakmeter II. Background levels of the gas being used as the tracer can be filtered electronically so that meter deflection is caused by levels of tracer above background. Relative concentrations over a distance can be determined; this will be sufficient for leak location operations.

PTI obtained a Model 56 Leakgun and used it search for the buried leaks at Saratoga. Figure 4.13 shows the unit in use, with the bore-hole probe in place. Note that the unit consists of a hand-held gun, and an argon tank that is provided with a belt for carrying at the waist.

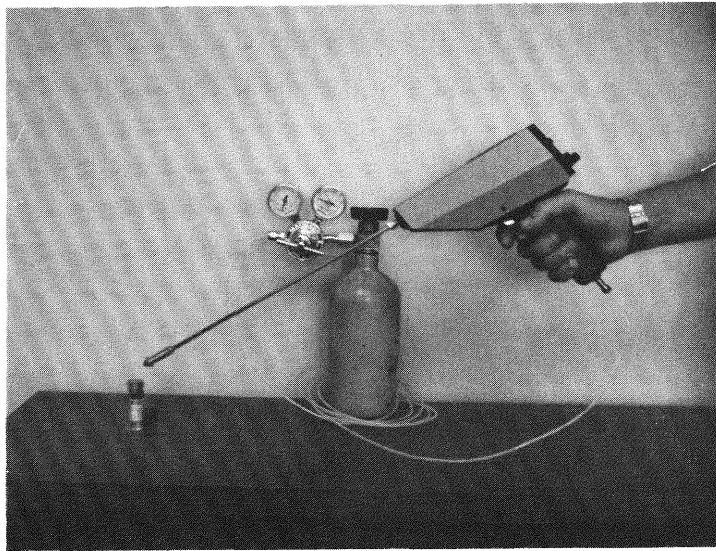


Figure 4.13. Leakgun in use at Saratoga.

A few modifications were made and accessories were added to make it more suitable for utility use; the unit worked quite well and should be a good instrument for operation by trained utility personnel in searching for cable oil leaks, or leaks from high pressure gas-filled lines traced with  $SF_6$ . The unit should be very effective in locating small leaks of  $SF_6$ . Even on the least sensitive scale, however, it will probably be too sensitive to use to locate leaks in  $SF_6$ -filled substation equipment where background levels are generally quite high.

It should be emphasized that, although the Leakgun was developed for field use, it is still a delicate and expensive instrument. It should be operated by technicians trained in its use rather than by untrained mechanics.

The Model 56 Leakgun and its accessories were presented to EPRI at the end of the Leak Location contract.

#### 4.6 ADDITION OF THE TRACER

As noted earlier, if SF<sub>6</sub> saturates the cable oil at the 69 kPa (10 lb/in<sup>2</sup>) pressure in the pumping plant pressurizing tank, a 1420 liter (375 gallon) oil spill would need to occur before a sufficiently large quantity of tracer reaches the surface. At a leak rate of 38 liters/hour (10 gallons/hour) this would take 38 hours.

For a system having slow (38 liter/minute, 10 gallon/minute) oil circulation with the oil dumping into the pressurizing plant storage tank, several weeks should be adequate for SF<sub>6</sub> blanketing the tank to saturate the oil. Introduction of the gas into the soil would thereafter begin immediately upon a leak.

If, however, there is a desire to not add the tracer until a leak is verified and the approximate location of the leak is known, the gas should be added to the line at the manhole upstream of the leak, the gas/oil mixture should flow until it appears at the downstream manhole, and above-ground leak location should begin several hours after that time.

After the leak is located, that section of pipe should be flushed with fresh oil. The 18000 liters (5000 gallons) or so of oil flushed from the line can be vacuum-treated and reintroduced to the cable system.

Appendix C , Leak Location Manual, provides detailed steps for the above procedures.

#### 4.7 FUTURE WORK

The tracer detection system represents current state-of-the-art in portable electron capture detectors; no further work is suggested other than monitoring the progress of new developments in the field.

Although extensive testing was done at Saratoga on the permeation of the tracer through soil and backfill, there was not an opportunity to try the system in city streets on an actual leak. It is recommended that during the first leak location efforts by a utility, great care be taken to gather sufficient data on use of the system to allow improvements in design of the leak location system.

There was no occasion in the leak location contract to change the blanketing gas in an oil pumping plant storage tank from nitrogen to SF<sub>6</sub> and determine the length of time it took the tracer to reach the far end of the feeder. This should be done on the first utility use of the SF<sub>6</sub> blanket.

There was also no occasion to add SF<sub>6</sub> at high pressures to the cable line itself and to monitor its passage downstream. This, too, should be carefully monitored during its first field trials.

Testing done by PTI at Saratoga and earlier testing done by Ontario Hydro showed the SF<sub>6</sub> to linger in the soil for many months. Field tests should be done to determine the feasibility of performing a scan of background levels of SF<sub>6</sub> in the vicinity of an earlier leak, then determining elevations above background as SF<sub>6</sub> evolves from a new leak in the same area.



SECTION 5  
COMPATIBILITY TESTS

5.1 INTRODUCTION

As stated in Section 4, the ranking of tracer gases that might be considered for leak location was based on the expected ability of the gas to diffuse through the soil, the detectability of the gas by an instrument suitable for field use, and the expected compatibility with oil/paper insulation.

Although there had been some research done in the past on compatibility of gases with cable oil/paper systems, additional work was needed for gases considered for tracers for leak location. A careful analysis of aging effects of each of the candidate gases was required on a common basis and in comparison with nitrogen gas which normally blankets the oil storage tank in a High Pressure Oil Filled (HPOF) cable system.

Once the list of candidate gases was chosen and the outline of the testing program was prepared, several organizations having the necessary facilities were evaluated. A subcontract was awarded to Institut de Recherche de l'Hydro Quebec (IREQ) who had the required number of test cells and who had long experience in this type of testing and analysis. Much of the information presented in this Section is taken from the IREQ final report to PTI on the compatibility tests. The full IREQ report to PTI is given in Appendix B.

## 5.2 SUMMARY

Compatibility tests were performed on model cables impregnated with a mixture of 70% polybutene filling oil and 30% Sun XX impregnating oil. Aging was done for 750 hours at 120 C and an electrical stress of 158 kV/cm (400 volts/mil). Loss tangent measurements were made periodically to determine degree of degradation of the sample, corona measurements were made as needed, and breakdown tests were performed on all samples that completed the aging. Tracer gases consisted of nitrogen ( $N_2$ ), helium (He), octafluorocyclobutane ( $c-C_4F_8$ , Freon c318), tetrafluoromethane ( $CF_4$ , Freon 14), and sulfur hexafluoride ( $SF_6$ ). These gases saturated the oil mixture at a pressure of 238 kPa (19.8 psig). For the  $SF_6$ , this amounted to a concentration of XXXXml  $SF_6$  per milliliter of the oil mixture.

Helium did not perform well. Of the other samples,  $c-C_4F_8$  was slightly preferable based on a slightly higher average breakdown stress, and nitrogen,  $SF_6$ ,  $c-C_4F_8$ , and  $CF_4$  showed approximately the same aging rate as measured by dissipation factor measurements. This aging was greatly accelerated over that expected in field service to allow meaningful results in a reasonable length of time. The important conclusion is all of the tracers performed at least as well as nitrogen, which has a long history of use in the field.

Based on the results of these tests, there should be no problem in adding  $SF_6$ ,  $c-C_4F_8$ , or  $CF_4$  in moderate quantities as a tracer to an oil/paper cable system. (See Section 4 for a discussion of the quantities required for detection in city streets).

## 5.3 EXPERIMENTAL APPARATUS

All compatibility testing was done in the IREQ laboratories, Varennes, Quebec. Cable paper was donated by the Pirelli Cable Corporation, Sun XX was donated by the Sun Oil Company, Underground Systems, Inc. and Phelps Dodge Cable and Wire

Co. and polybutene and tracer gases were provided by PTI. The model cables and test equipment, which IREQ had characterized very thoroughly in earlier programs, are described in the following paragraphs.

### 5.3.1. Cable Models

The main parts of a typical cable model used for the study are identified in Figure 5.1. One layer of duplex paper was applied, with a 1 mm (0.04 inch) overlap between adjacent turns, on the copper conductor 12.7 mm (1/2 inch) in diameter and 305 mm (12 inches) in length. Four layers of kraft paper tapes 25.4 mm (1 inch) wide and 124  $\mu$ m (5 mil) thick were then lapped under constant tension with a nominal registration of 35/65 and a 1 mm (0.04 inch) butt-gap. A single layer of 127  $\mu$ m (5 mil) thick tin foil applied over the insulation formed the low voltage electrode. The stress cones were clad with tinned copper wire which was insulated from the low voltage electrode by a small kraft paper ring. A completed sample is shown in Figure 5.2.

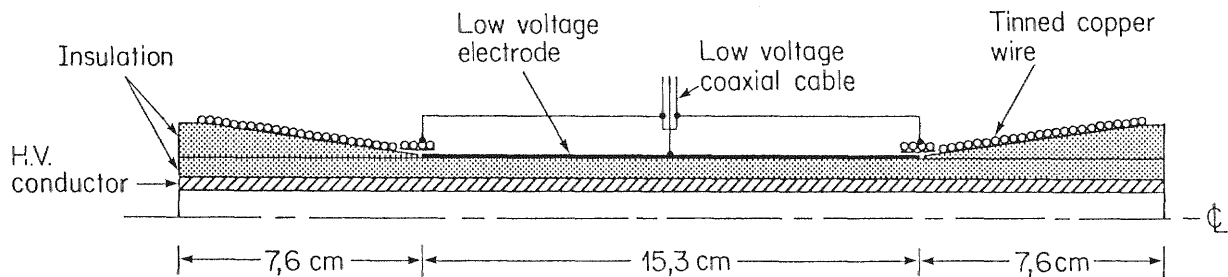


Figure 5.1. Schematic Diagram of Cable model.

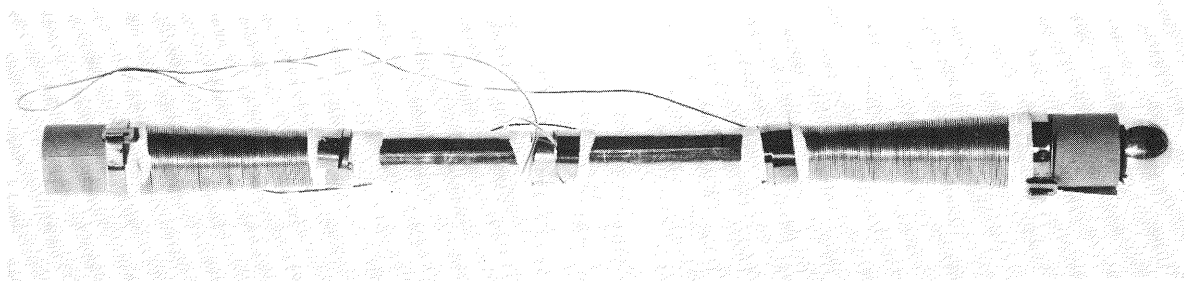


Figure 5.2. Completed Cable model.

The cable models were built on a winding lathe designed at IREQ especially for cable model construction and located in a controlled atmosphere room. This allowed the accurate control of the registration and the tension applied on the tapes. The stress cones were automatically wound with the required profile. These features provided very good uniformity among samples prepared according to a given set of parameters.

### 5.3.2 Drying and Impregnation

The impregnation apparatus shown in Figure 5.3 permitted the simultaneous drying and impregnation of four cable models. The vacuum system consisted of a sorption pump for rough pumping and degasification of the impregnating fluid, and an ion pump for drying the cable models.

The oil was degasified at 100 C and 0.65 Pa (5 microns) in two of the glass cylinders, and the sample was vacuum dried in the third cylinder at 110 C and  $1.3 \times 10^{-3}$  Pa (0.01 microns).

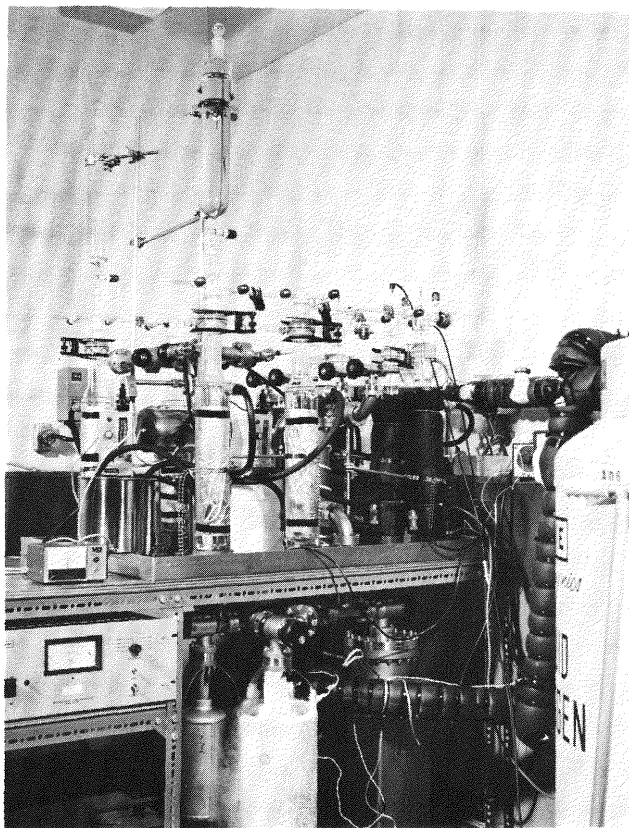


Figure 5.3. Drying and Impregnation Apparatus.

### 5.3.3 Test Cells

Two types of cells, shown in Figure 5.4, were used for the tests. Both were made of borosilicate glass with a glass-to-metal joint for connection of the stainless steel gas line. The high voltage connection consisted of a copper rod passing through the top of the cell, and low voltage connections were made with a Teflon coaxial cable going through the side wall. All feedthrough parts and o-rings that contact the oil were made of Teflon.

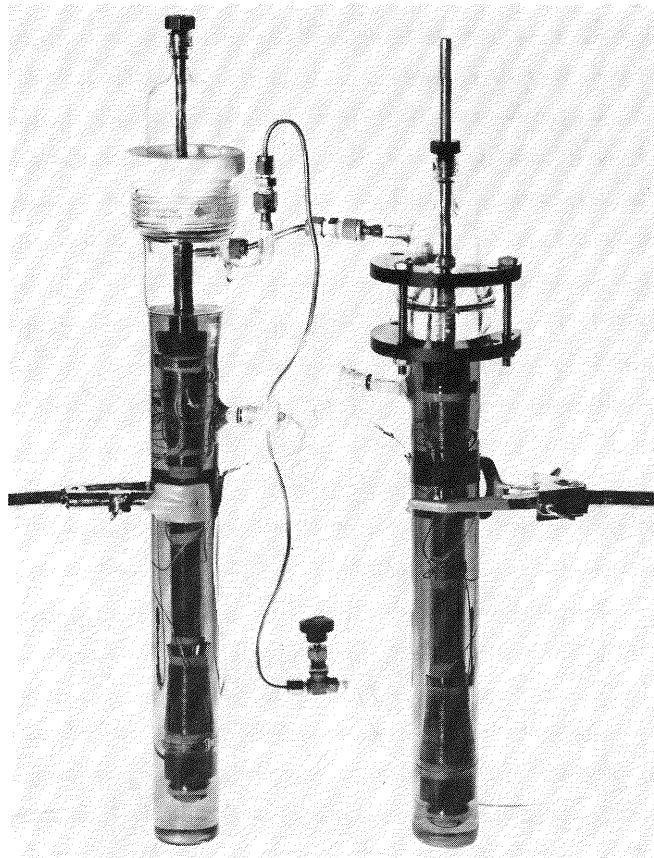


Figure 5.4. Glass Test Cells.

#### 5.3.4 Testing Equipment

The oven used for aging had a capacity of  $0.16 \text{ m}^3$  ( $5.7 \text{ ft}^3$ ) and could hold twenty of the glass test cells. With the temperature set at  $120 \text{ C}$  and the oven filled with cells, the temperature differential throughout the oven was less than  $0.4 \text{ C}$ .

Loss tangent measurements were performed using a high voltage capacitance bridge, Guildline Model 9910, and corona measurements were made on a Biddle Partial Discharge Detector system at a minimum detection sensitivity of  $1 \text{ pC}$ .

#### 5.4 TEST SCHEDULE

A test schedule was developed to age the samples in a reasonable length of time by accelerating temperature, electrical stress, degree of contaminants in the oil, and amount of the tracer.

A fourfold replication was planned. The large number of previous tests on cable models at IREQ had shown that threefold replication was adequate; the fourth sample per test was added should there be a problem with one of the samples. For later tests, only threefold replication was used.

The following test conditions were observed:

- Duration of test: 750 hours
- Temperature: 120 degrees C
- Pressure 238 kPa (19.8 psig)
- Electrical stress: 15.8 kV/mm (400 V/mil)
- Frequency: 60 Hz
- Oil: blend of 70 percent low viscosity polybutene with 30 percent Sun XX
- Paper: good quality kraft paper 124 mm (5 mil) thick with a density of 1.02 g/cm<sup>3</sup>
- Level of contaminants added:
  - Moisture: 0.1 percent in paper
  - Oxygen: 3.6 ml/liter
  - Copper: 4 ppm copper octalate
- Tracer concentration: at saturation pressure of 238 kPa (19.8 lb/in<sup>2</sup>).

- Tracer gases:

Helium

Nitrogen

Tetrafluoromethane (CF<sub>4</sub>)

Sulfur Hexafluoride (SF<sub>6</sub>)

Octafluorocyclobutane (c-C<sub>4</sub>F<sub>8</sub>)

The contaminants were added to ensure the presence of any component that might be present in a cable system, and which might catalyze the degradation of the dielectric.

## 5.5 TEST RESULTS

Two sets of aging tests were planned. The first set would provide data on the preferred tracers. The second set would add other tracers if desired, and would provide confirmatory tests on the best candidate from the first set of tests.

Test difficulties required early termination of the first set of tests, however, so that the second set provided the majority of data from the study.

### 5.5.1 Aging Test #1

Ten samples were aged: two nitrogen, four CF<sub>4</sub>, and four c-C<sub>4</sub>F<sub>8</sub>. One CF<sub>4</sub> sample was initially removed from test because of a broken lead and was thermally aged without voltage for later testing; the other nine samples were aged at full voltage (9 kV).

Figures 5.5a-c show the results for nitrogen, CF<sub>4</sub>, and c-C<sub>4</sub>F<sub>8</sub> respectively. Note that the initial dissipation factor (DF,  $\tan \delta$ ) was about 0.5 % for each of the samples, compared to a value of about 0.2% typically found for the cable models. This is mostly due to the intended level of contaminants of water, oxygen, and

copper. The substantial increase in DF for the samples after 675 hours led to terminating the aging at that time.

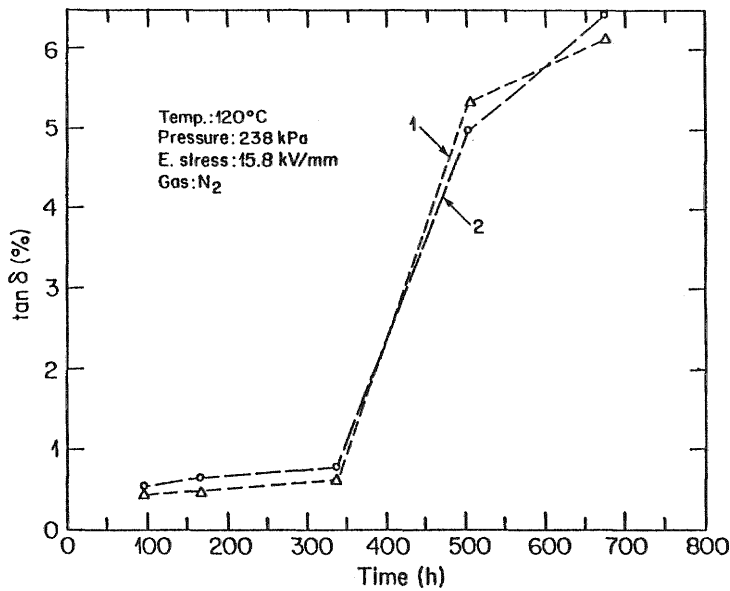


Figure 5.5a. Tan  $\delta$  vs Time of Cable Models  
Pressurized with N<sub>2</sub> Tracer Gas.

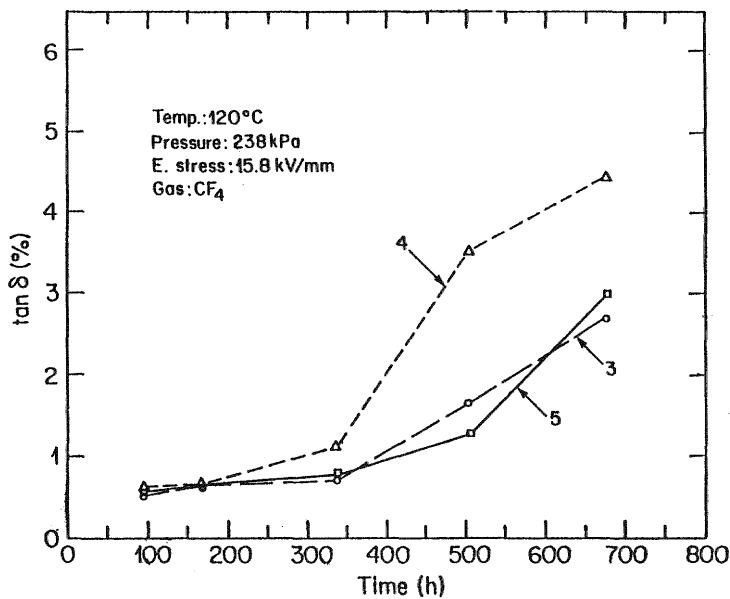


Figure 5.5b. Tan  $\delta$  vs Time of Cable Models  
Pressurized with CF<sub>4</sub> Tracer Gas.

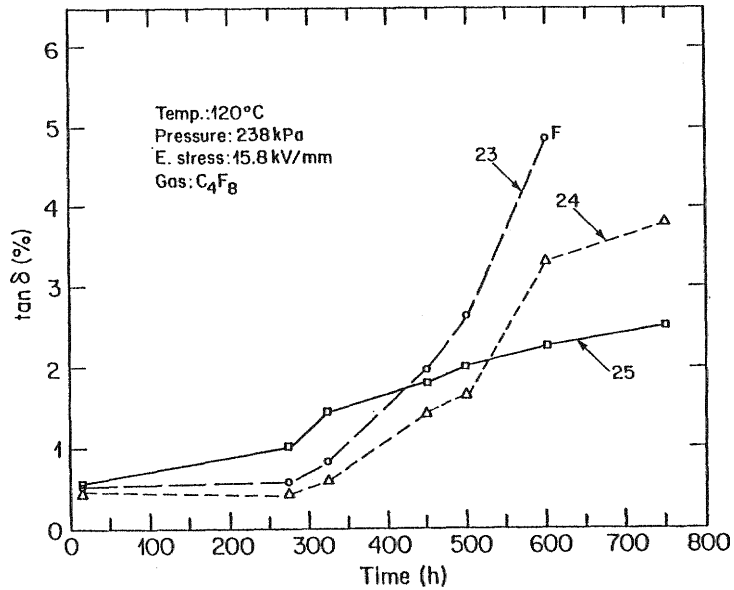


Figure 5.5c. Tan  $\delta$  vs Time of Cable Models  
 Pressurized with c-C<sub>4</sub>F<sub>8</sub> Tracer Gas.

IREQ measured the DF of the polybutene oil that was used, and found it to be 3% compared to the 0.05% expected, and the dry paper DF was found to be 0.23%, well within the normal range.

Although oil dissipation factor doesn't have a large contribution to cable DF (because of the relatively small amount of oil in the cable), the very high DF for the polybutene probably contributed strongly to the 0.5% measured for the models.

It was therefore decided to treat the polybutene before beginning the second series of aging tests.

### 5.5.2 Aging Test #2

No additional low viscosity polybutene could be obtained in time to complete the tests so IREQ treated the existing oil by filtering it under vacuum at 110 C

through fullers earth at that temperature. The average DF of the treated oil was 0.04% at 100 C. The DF for the Sun XX was 0.2%, slightly above specification, and the DF of the resulting mixture was 0.12%. The dissipation factor of representative cable models was 0.31% at 85 C, before addition of controlled contaminants.

Sixteen cable models were tested in the second set of aging tests: three each of helium, nitrogen,  $CF_4$ ,  $SF_6$ , and  $c-C_4F_8$ , plus one additional  $SF_6$  model after a sample failed during the tests.

Results of the aging tests are shown in Figure 5.6 a-e. Readily apparent is the rapid increase in DF for the samples with the helium tracer. Nitrogen,  $CF_4$ , and  $c-C_4F_8$  all performed about the same, with a change in the aging rate occurring between 400 and 600 hours. The  $SF_6$  samples did not perform as well. The three original samples failed between 275 and 350 hours. A fourth sample was added after the third failure; that sample had only a moderate increase in DF for the 435 hours it was under test.

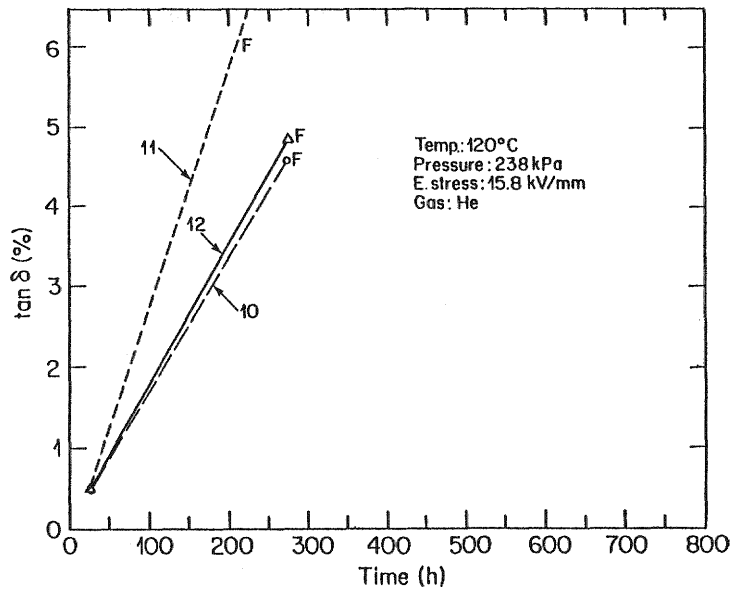


Figure 5.6a. Tan  $\delta$  vs Time of Cable Models  
 Pressurized with He Tracer Gas.

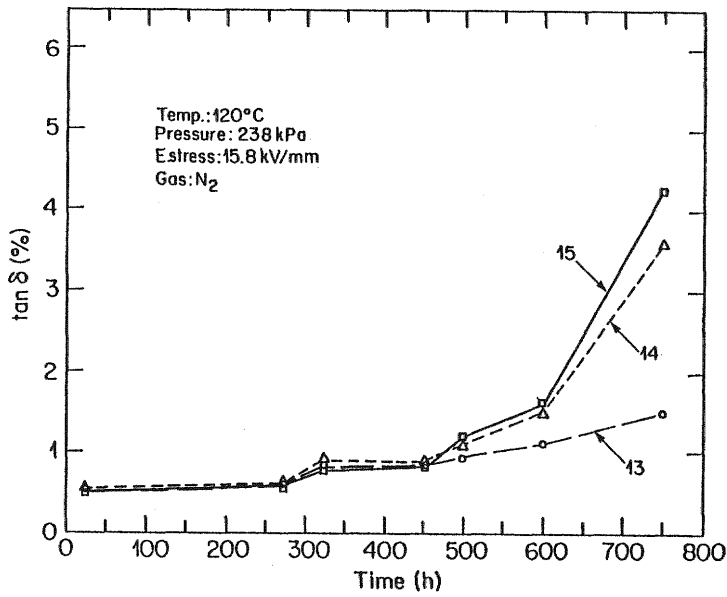


Figure 5.6b. Tan  $\delta$  vs Time of Cable Models  
 Pressurized with N<sub>2</sub> Tracer Gas.

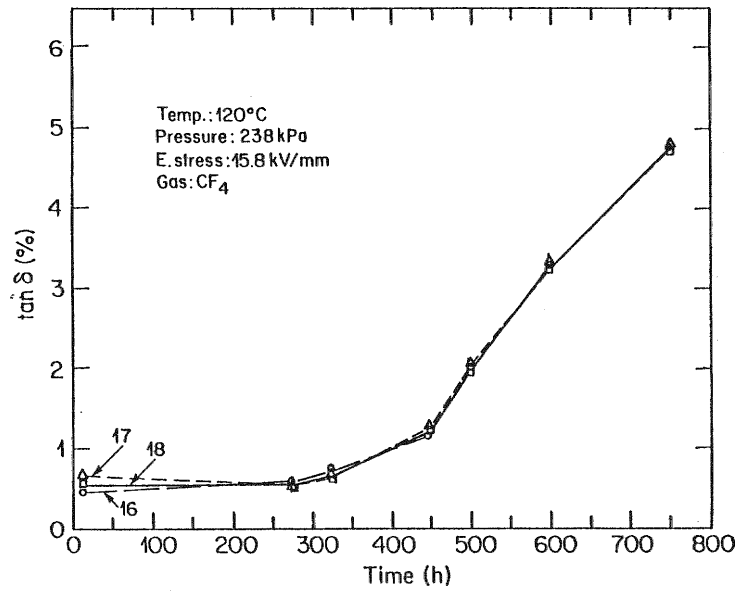


Figure 5.6c. Tan  $\delta$  vs Time of Cable Models  
 Pressurized with CF<sub>4</sub> Tracer Gas.

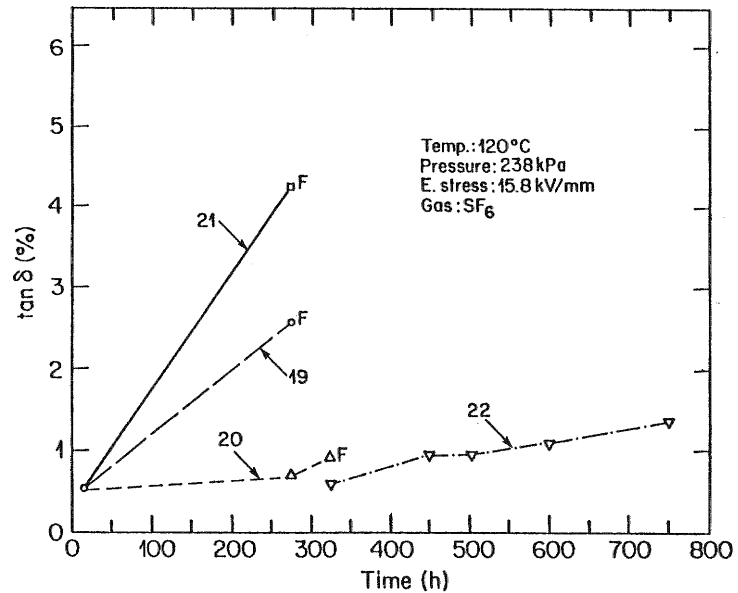


Figure 5.6d. Tan  $\delta$  vs Time of Cable Models  
 Pressurized with SF<sub>6</sub> Tracer Gas.

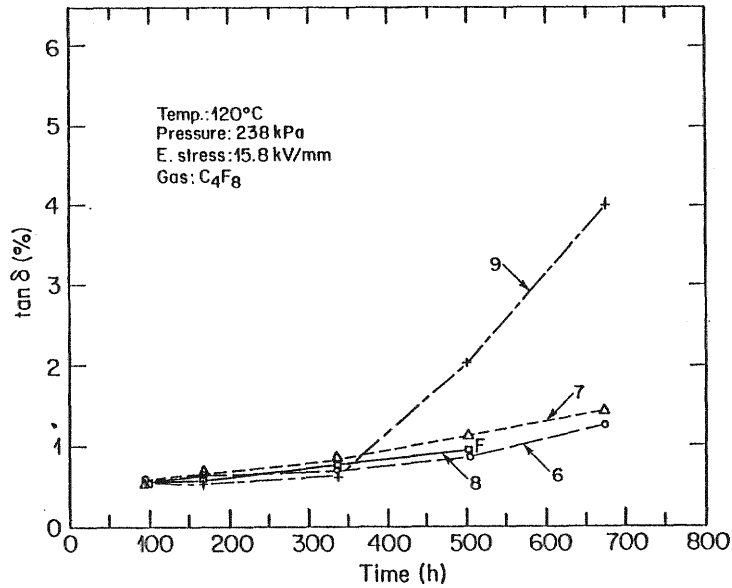


Figure 5.6e. Tan  $\delta$  vs Time of Cable Models  
Pressurized with c-C<sub>4</sub>F<sub>8</sub> Tracer Gas.

### 5.5.3 Breakdown Tests

All of the samples that survived the aging tests, plus four nitrogen-pressurized control samples that were not aged, were tested to breakdown at 85 C, 238 kPa (19.8 psig) pressure, and ramped 60 Hz voltage raised at 500 volts/second. The samples were tested in the same glass cells used for aging tests. Table 5.1 summarizes the results of breakdown tests. The uncontaminated and contaminated, unaged nitrogen samples had a similar breakdown stress of about 480 kV/cm (1220 volts/mil); aging resulted in about a 10% reduction in breakdown stress. The SF<sub>6</sub> and CF<sub>4</sub> samples had a slightly lower average breakdown stress than the aged nitrogen-pressurized samples, and the c-C<sub>4</sub>F<sub>8</sub> cables had a slightly higher average breakdown stress.

TABLE 5.1

## AC BREAKDOWN OF CABLE MODELS

Gas	Model No.	Breakdown Voltage (kV)	Breakdown Stress (kV/mm)	Average Breakdown Stress kV/mm
Test #1				
N2	1	25.5	46.1	43.0
	2	22.0	39.8	
CF4	3	25.0	45.2	42.8
	4	22.0	39.8	
	5	24.0	43.4	
c-C4F8	6	25.5	46.2	46.6
	7	26.2	47.4	
	9	25.5	46.2	
Test #2				
He**	12	26.1	47.2	47.2
N2	13	24.4	44.1	44.1
	14	24.4	44.1	
	15	24.4	44.1	
CF4	16	23.4	42.3	41.6
	17	23.4	42.3	
	18	22.2	40.2	
SF6	22	23.4	42.3	42.3
c-C4F8	24	26.8	48.5	46.4
	25	24.5	44.3	
Unaged Samples, Non-Contaminated				
N2	26	27.0	48.8	48.8
	27	27.0	48.8	
Unaged Samples, Contaminated				
N2	28	26.2	47.4	48.0
	29	26.8	48.5	

The surprisingly high breakdown stress for the one surviving helium sample is probably due to the small degree of aging--- the sample was removed from test after 275 hours because of high partial discharges. The level of discharge, although high, apparently was not great enough to damage the sample in 275 hours. There was also not enough damage to give a low breakdown stress during the rapid rise breakdown test.

#### 5.5.4 Dissection of Samples

All cable models were dissected following completion of the tests. The following observations were made:

1. Of the 29 samples dissected, only two failed outside of the test area (the two failed in the gap separating the electrode from the stress cone).
2. All punctures but five occurred radially through two paper layers and two butt gaps. This is the normal breakdown for thin wall cable models built with a 35/65 registration. The five other breakdowns occurred through insulation walls having a slight misalignment at the registration.
3. All samples (other than the helium, which were removed from test early because of very high partial discharge readings) that failed during aging showed partial discharge activity in the region of failure for an extended period of time.

4. Some of the samples that did not fail during the aging tests had traces of partial discharge activity visible on the insulation.

#### 5.6 DISCUSSION

The aging tests were performed on cable models having a rather high initial level of dielectric losses due to the planned levels of contamination of the oils used as impregnants, and to a somewhat high power factor of the polybutene provided by PTI. Some instability of the power factor could therefore be expected. All models but five i.e., Nos. 10, 11, 12 (He) and Nos. 19, 21 ( $\text{SF}_6$ ) experienced about the same rate of increase of dissipation factor for the first 300 hours. The steady rise of the losses may be related to the presence in the oil of an increasing number of ions some of which were already in the insulation, others coming from various physical and chemical processes.

Note the rapid initial increase in DF for the two  $\text{SF}_6$  samples (#19 and #21). This is indicative of defects in the samples rather than action of the tracer gas. The other two  $\text{SF}_6$  samples had a smaller increase in DF with time than for most other samples. Analyses of these results and those of the breakdown tests on the  $\text{SF}_6$  models leads to the conclusion that the  $\text{SF}_6$  tracer did not on balance perform any worse than the other tracers.

It is interesting to note that a new phenomenon appeared around 300 hours, indicated by raising of the DF rate of increase of most of the models. No satisfactory explanation has yet been found. The examination of the test schedules did not reveal any incident that could have triggered the effect. The possibility of having had a similar hidden problem twice with the testing apparatus is very remote since the two aging tests were done at different times. The models that showed the sharpest increase of their losses had traces of partial discharge activity on the paper. It would be difficult however to solely consider this partial discharge activity to explain the phenomenon since other models which also

had a faster increase of DF after 300 hours did not show any traces of corona when dissected.

Since the samples pressurized with helium were removed after less than 300 hours of aging, the corona activity, although very intense, was not strong enough to damage the papers. The high breakdown stress mentioned in Section 5.5.3 obviously shows that the insulation had not been permanently damaged when its aging was aborted. Most of the helium gas probably had escaped from the oil during the several weeks between termination of the aging and the corona and breakdown tests and all the gas bubbles in which the discharges were occurring had disappeared.

The ac breakdown tests showed a slight advantage of  $C_4F_8$  models despite the fact that most of these models had spots of carbonized paper. Unaged nitrogen pressurized models had, as one could have expected, breakdown stress values higher (by about 10 percent) than those of the corresponding nitrogen aged models. The dispersion range of the breakdown values of all the 22 models including the unaged samples, is rather small with a standard deviation of about 6 percent. This fact points out the difficulty that one may have in trying to select the best candidate tracer gas from the breakdown test data. All gases behave equally well.

## 5.7 CONCLUSION

The compatibility tests performed on the five gases selected as potential candidates to be used as tracer gases for oil leak location in pipe cables lead one to conclude that:

1. Since the oil used for impregnation of the cable models had a high initial dissipation factor, the increase of the DF of several models may

have been partially caused by the presence of the original oil contaminants rather than by the interaction of the tracer gases with the insulation.

2. Helium gave the poorest results with very strong corona activity in the three models at an early stage in the aging.
3. The voltage breakdown gradients were similar for all the gases with a slight lead however for the  $c\text{-C}_4\text{F}_8$ .
4. Dissipation factor versus time data of models that did not exhibit a dielectric losses runaway show that nitrogen,  $\text{SF}_6$  and  $c\text{-C}_4\text{F}_8$  gave very similar results. The initial dissipation factors and slope of the DF versus time curve, are higher than would be expected for good cable systems. This was intentional to allow useful results to be obtained in a reasonable length of time. The comparison of results of other tracers to the standard, nitrogen, showed that all tracers (other than helium) are acceptable in the concentrations tested.

The gas absorbing capacity of the oil may have been hampered by the presence of the tracer gas with, as a consequence, a smaller ability of the oil to absorb gases such as those resulting from the thermal degradation of the paper. Lower concentrations of tracer gases might have possibly given less corona problems.

It should also be noted that an analysis of the gases dissolved in the oil (presently kept in sealed containers by IREQ) might help in the selection of a tracer gas by identifying the decomposition by-products of the gases, some of which might be potentially harmful to the insulation and also to the personnel.

## 5.8 FUTURE WORK

The work completed at IREQ demonstrates the compatibility of several important tracer gases (c-C<sub>4</sub>F<sub>8</sub>, CF<sub>4</sub>, and SF<sub>6</sub>) with oil/paper insulation under simulated long term aging of cable models.

No work was scheduled on the effect of the tracer gases in the divergent electrical fields, of potheads for example. A utility that has the tracer installed permanently in the cable oil needs to vent potheads if line pressure drops below the saturation pressure of the tracer gas. The venting is presently specified for HPOF cable systems having nitrogen-blanketed oil reservoir tanks. If a utility feels that it will not be possible to vent potheads, then further work should be done to determine the effect of the tracer in potheads that have experienced low pressure operation.

IREQ has kept samples of oil from each of the cable models that was tested. It would be useful to identify the decomposition by-products of the gases as an indication of potential harm to the cable system or, if in sufficient amounts, possibly even harm to personnel.

SECTION 6  
NOVEL APPROACHES

6.1 INTRODUCTION

The optimization of flow direction indicators and tracer gases were applications of state-of-the-art methods of leak location that had been previously attempted for underground cable systems or other buried pipes.

There are several other approaches that had not been evaluated before, or which represented radical departures from traditional leak location techniques. One of the primary objectives of the Leak Location program was to evaluate novel systems theoretically, and experimentally where indicated by the theoretical analysis.

Many novel systems were reported in various technical and popular publications during the course of the contract, but upon evaluation have no relevance to the leak location study. Those systems are not described in this report; the leak location approaches tabulated below are those in which the chances of success appeared strong enough to justify at least a small experimental program.

The systems tested were:

- Leak Location Dogs
- Subsurface Radar
- Radioactive Tracers
- Earth Electrical Resistivity
- Infrared Analysis
- Microphony

## 6.2 SUMMARY

Leak location dogs proved to be a very effective tool for rapidly pinpointing a leak after it had been isolated to a length of less than a few kilometers. The dogs were successful in locating the odor of the cable oil alone, without the need for additives. They were trained to separate the odor of old subsurface cable oil from new subsurface cable oil, and to discriminate between fresh cable oil on the surface of the street versus that from a buried leak. Subsurface radar and microphonics had some degree of success; initial tests showed little chance of success with earth electrical resistivity and infra-red analysis. The radioactive tracer may be feasible.

## 6.3 LEAK LOCATION DOGS

### 6.3.1 Principle

As noted in the State of the Art review, dogs are well known to have a very acute sense of smell; news stories frequently describe the ability of trained dogs to locate concealed narcotics or explosives, to track days-old scents of persons, or even to sniff out gypsy moth eggs having a density of a few eggs per thousand square meters.

EPRI had investigated the possible use of leak location dogs, and PTI had independently contacted the U. S. Customs Service to discuss the use of trained narcotics-detection dogs for retraining as leak location dogs. It appeared that the use of trained tracking dogs may have a good chance of success; subcontracts were placed with two organizations that had different approaches to training leak location dogs.

### 6.3.2 Guardian Training Academy

Guardian Training Academy (GTA) of Windsor, Ontario, had extensive experience in training dogs for competition tracking; the Academy had trained several champion trackers. Of more interest to the leak location program, however, was work done by GTA in the early 1970's to train three German Shepherds to recognize the smell of trace amounts of butyl mercaptan, the odorant used in natural gas.

The dogs had been used to locate more than 150 leaks in a 150 km (93 mile) length of natural gas pipeline buried as much as 4 meters (12 feet) under frozen earth. The dogs had apparently found all of the leaks, even minute ones, and had given no false indications.

GTA had also worked with Bell Telephone of Canada to train dogs to locate leaks of SF<sub>6</sub> and freons that had been added as tracers to buried telephone lines.

A small subcontract was given to GTA in late 1979 to take two dogs that had previously been trained as tracking dogs, and teach them to recognize the odor of low viscosity polybutene. In addition, a small sample of butyl methyl sulfide, a powerful odorant, was given to GTA and the dogs were trained to recognize minute amounts of the odorant.

Basic training included the anointing of a dog's toys (sticks, balls) with successively smaller amounts of cable oil and teaching the dog to fetch the toy, then rewarding him when the toy was returned. Later the toys were buried just below the surface, then deeper, until the dogs began to dig the earth at the point they suspected the toy to be buried. The dog's response, called an "alert" is therefore to paw the surface at a point where he detects the odor of the cable oil. In each case, the dog would be rewarded for a successful find, with food and verbal praise.

A demonstration was conducted on several buried leaks at PTI's Saratoga R & D Center in January, 1980. The temperature was -15 to -16 degrees C (7-10 degrees F) during the demonstration and there were strong winds. After initial hesitation, both dogs located leaks of polybutene from probes that had been driven under asphalt pavement, and from a buried pipe under soil with no pavement. Both dogs appeared to be repulsed by the odorant, even when the butyl methyl sulfide was added to the oil at a concentration of less than ten parts per million.

Con Edison was kind enough to stage three leaks of low viscosity polybutene from actual HPOF cables, by driving probes out from a manhole wall then connecting the vent valve of the joint to the probes. Both dogs were successful in locating the simulated leaks, even in heavy-traffic areas of Manhattan, and in heavy snows with the attendant traffic problems in NYC.

A month later there was an actual leak in New York City. One of the dogs was taken to the city and he quickly located the general area of the leak. The leak was in a 62 cm (24 inch) diameter 50 m (150 ft.) long cable pipe 6 m (20 ft.) under a series of railroad tracks. The dog indicated on the ground surface at both ends and the middle of the casing. There will probably be many instances where oil or vapors travel some distance from the leak and the leak cannot be pinpointed.

Figure 6.1 shows one of the dogs alerting to one of the staged leaks, and Figure 6.2 shows a dog pawing at the ground near the actual leak.



Figure 6.1. Ike Alerting At Staged Leak



Figure 6.2. Ike Alerting Near Actual Leak.

The success with these initial demonstrations led to the awarding of more extensive subcontract to GIA, to procure and train two dogs specifically for location of buried oil leaks. The intent was to have dogs selected based upon their expected ability to function well under stress and to work long periods of time searching for the leaks. (The major part of this program was funded by EPRI, and Con Edison contributed to the purchase and training of one of the dogs.)

After several months of interviewing potential candidates, GIA selected two young male German Shepherds, Thor and Rocky. GIA also chose and trained two handlers in the Windsor area. Both men had extensive experience in training and handling

of tracking dogs, and both had jobs that permitted them to respond on short notice to a leak location call.

The dogs had been under training for a month and a half of a two month program when Con Edison had an actual leak of low viscosity polybutene from a 345 kV cable. The dogs and handlers were in NYC within five hours of notification of the leak, and they found the leak after two hours' searching.

The leak was in a substation at a point where stainless steel riser pipes passed under equipment footing. A 345 kV transformer failure had occurred the previous day; the dogs were able to find the cable oil leak in earth that was saturated with fresh transformer oil.

A final demonstration was conducted in NYC in March, 1981, after Con Edison had again kindly staged leaks from actual cable circuits. About 190 liters (50 gallons) of oil had been leaked at each location, about 1.2 meters (4 feet) under concrete/asphalt pavement, and about 12 meters (40 feet) from the edge of the manhole along the feeder route. No oil was leaking during the tests; the oil was leaked early in the morning before the tests, and a nitrogen supply was connected to the probe for some tests, with the nitrogen supply set at 1/2 atmosphere.

The dogs searched a several-kilometer long feeder route at the rate of a kilometer in ten minutes. The actual pace was faster---the dogs had to wait for traffic lights at intersections.

Both dogs were not positive of the location of at least one of the leaks during the initial fast search, but they correctly indicated all leaks during subsequent more intensive searching.

Con Edison construction crews were draining oil at one location on the second day of testing and there was much fresh cable oil present on the street surface, on rags, etc. Both dogs ignored these surface spills and correctly indicated the underground leak.

In addition to the staged leaks, Con Edison had an actual leak of Sun #6 on an abandoned feeder in a generating station. A small sample of that oil had been sent to GTA and the dogs were briefly introduced to its odor. They searched the 1 km long feeder route and both dogs indicated a spot near one end of the feeder. Later inspection after Southwest Research Institute's dogs had indicated the same spot indeed showed that a large quantity of Sun #6 was present at a depth of 4 meters (12 feet).

Figure 6.3 shows Rocky searching for a leak, and Figure 6.4 shows Thor pawing at one of the leaks.



Figure 6.3. Rocky Searching for a Leak.



Figure 6.4. Thor indicating a Leak.

### 6.3.3 Southwest Research Institute

Southwest Research Institute (SwRI) had submitted a proposal to EPRI in 1978 for developing leak location dogs as part of the then-emerging leak location program. The SwRI proposal was based on earlier work done on the training of dogs to locate concealed narcotics and other controlled substances, and to locate buried explosive devices. The program was not funded in 1978 because of a desire to first pursue less revolutionary methods of leak location. SwRI conducted a demonstration under the EPRI/PRI Leak Location Contract in mid-1979 of the ability of one of their trained dogs to be retrained to natural gas containing butyl mercaptan, and to locate buried leaks of the gas. An initial program was funded in 1980 to purchase and train two or more leak location dogs, demonstrate them in an urban environment, and make them available to utilities for leak location operations.

SwRI obtained and evaluated over twenty dogs from the San Antonio area before selecting two for further training: Buster, a golden Retriever and Rebel, a German

Shepherd. Three English Foxhounds were obtained from Ohio State University and one, Woody, was kept for training. The rejected animals were unacceptable because of temperament, health, or ability to adapt to training methods.

Laboratory training consisted of a three-choice olfactory discrimination apparatus as shown in Figure 6.5. Three stainless steel funnels are used with teflon tubing connected to a closed glass vessel containing the liquid of interest. Nitrogen gas or compressed air was metered through microvalves, passed over the liquid, and to the funnels through the tubing. One of the funnels had the cable oil odor, the other two had either no odor or in later stages of the tests, negative odorants such as motor oils. The dogs were taught to sit when they recognize the odor of the cable oil. This response is a holdover from earlier SwRI programs where dogs were taught to search for buried land mines, and where pawing would produce undesired verification of the find.



Figure 6.5. SwRI Laboratory Olfaction Apparatus.

After the dogs became nearly 100% proficient in choosing the correct odor, field tests began first with fairly large (several milliliter) samples on the surface, then with successively smaller amounts buried at increasing depths. Testing then progressed to shopping malls and other light-traffic areas, then finally to downtown San Antonio. Probes were also driven to a 1 meter depth under access roads to major highways and oil was forced through the probes.

The dogs had undergone training for about seven months when Woody and Buster were taken to New York City to search for the staged leaks described in Section 6.3.2. Rebel had continued to work well, and is being kept as a backup should there be a problem with Woody or Buster.

The demonstration in NYC was done the day after GTA had completed the two-day trial. There had been a heavy snowfall the night before, which was new to the dogs and also created traffic problems on city streets. The dogs were unaffected by the snow after initial investigations; traffic remained congested all day.

The dogs moved at a slightly faster speed than those from GTA and the SwRI dogs also searched with their heads high rather than sniffing the pavement as did the GTA dogs. Buster and Woody were also effective in finding the staged oil odors, and they appeared able to detect more minute quantities of the odor. Continued evaluation of the different GTA and SwRI training methods will be of interest in the ability of the animals to detect the lower odor levels.

The one problem was that the Texas dogs had not been taught to discriminate between surface spills of polybutene and buried leaks; they gave several false indications.

The two dogs were taken to the generating station where they searched for the Sun #6 leak. Both dogs indicated the location that the two GTA dogs showed and in

addition the SwRI dogs indicated several other locations in the same area. It is possible that the leak, which had been present for several months, could have allowed oil to permeate other areas and the SwRI dogs were giving proper indications of traces of airborne vapors.

Figure 6.6. shows Woody searching for a leak and Figure 6.7 shows Buster sitting at a find.



Figure 6.6. Woody Searching for Buried Leak



Figure 6.7. Buster Alerting at a Leak.

#### 6.3.4 Summary---Leak Location Dogs

Both sets of dogs worked extremely well in actual city conditions. The Guardian Training Academy dogs needed to search an area carefully and would pinpoint the strongest odor from a buried leak; they would ignore surface spills of cable oil. The Southwest Research Institute dogs would alert at the slightest indication of a cable oil smell, whether it was from a surface spill or a buried leak.

An effective leak location system would be to have the two sets of dogs working---the SwRI dogs to rapidly indicate many locations of possible leaks and the GTA dogs to verify the locations and pinpoint the leak.

At the time of completion of the EPRI/PTI leak location contract, negotiations were initiated among Con Ed, GTA, SwRI and EPRI to sponsor an additional year of maintenance and training with GTA and SwRI. The dogs would be available for leak location searches for Con Edison, and any other utilities (after coordination with Con Edison) during that period.

## 6.4 SUBSURFACE RADAR

### 6.4.1 Principle

Subsurface radar systems radiate short duration electromagnetic pulses into the earth from an antenna on the surface. The pulses are reflected from interfaces in the soil and are picked up by the receiver section of the antenna. The signals are processed and a graphic recorder shows the profile of the returned pulses. Reflections are due to soil/rock interfaces or any anomaly or interface in which there is a discrete change of dielectric constant.

The subsurface radar system has been used by several utilities to map underground obstacles such as sewer lines, distribution cables, etc. that may interfere with installation of new cable systems. Of interest to the Leak Location program was experience by Florida Power and Light in cable location and in locating a gasoline leak from a buried storage tank by radar reflection.

The system has a possible application in oil leak location if the low-dielectric constant cable oil (about 2.2) creates an anomaly in the earth which typically has a dielectric constant of 12-16. Figure 6.8 gives a simplified block diagram of the subsurface radar unit (19).

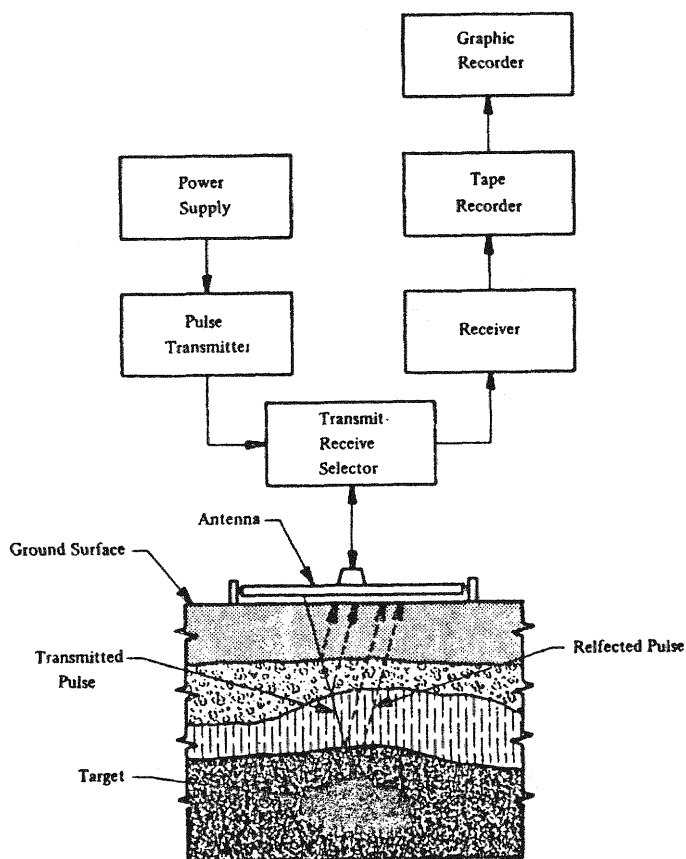


Figure 6.8. Simplified Block Diagram of Subsurface Radar Unit.

#### 6.4.2 Geophysical Survey Systems, Inc.

Geophysical Survey Systems, Inc. of Hudson, New Hampshire has supplied most of the subsurface radar equipment used by utilities. GSSI was contacted and kindly agreed to conduct a demonstration of their subsurface radar equipment to attempt to locate the controlled leaks on the buried pipe at Saratoga (see Section 4, Figure 4.2).

About 95 liters (25 gallons) of Sun #4 was leaked from each of the two controlled leaks. A 300 MHz antenna was traversed over the route of the pipe at a speed of about 10 km/hr, which is the rate used by utilities for locating buried pipes. (See Figure 6.9).

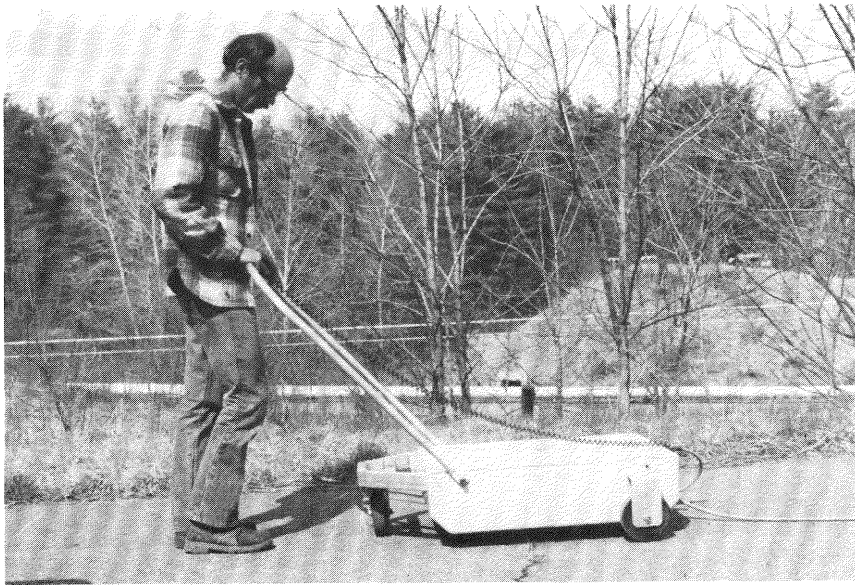


Figure 6.9. Radar Antenna at Saratoga Test Site.

There was a slight change of the reflected radar signal in the vicinity of the leaks, but the change was not large enough to be conclusive.

The antenna was then moved across the pipe. The pipe itself shows up quite clearly on the graphic recorder as seen in Figure 6.10. Unfortunately, the oil spill does not appear conclusively.

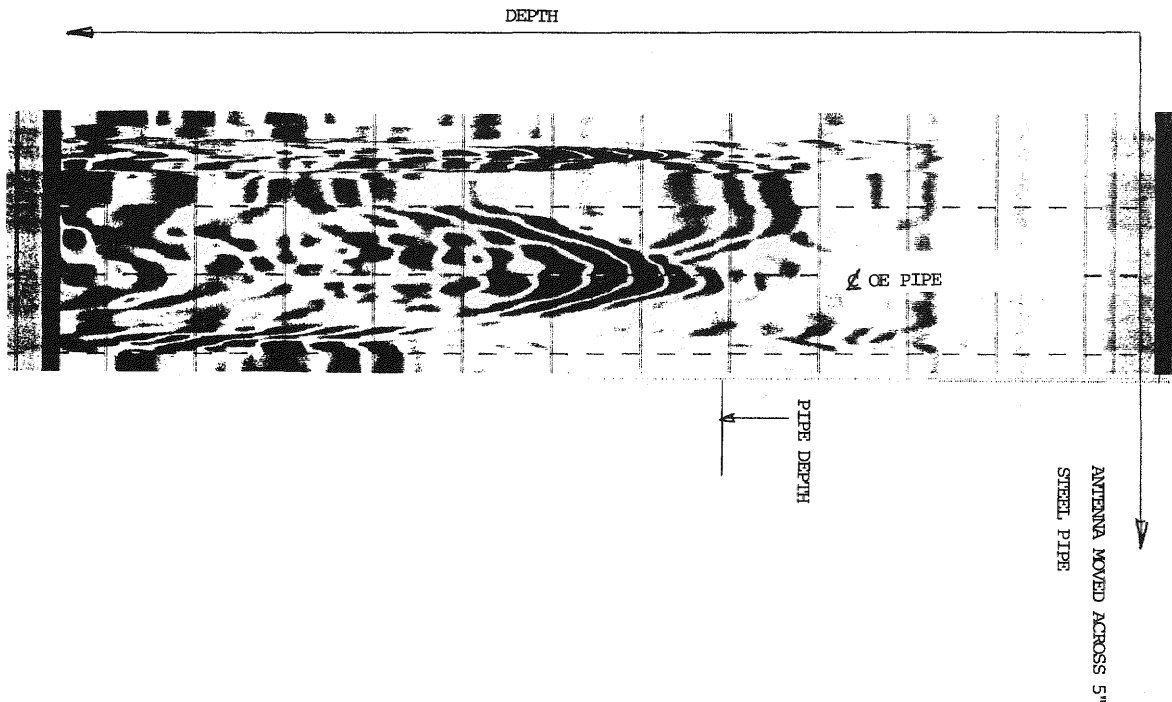


Figure 6.10. Graphic Recorder Output Showing Location of Pipe.

The GSSI antenna was then taken to another location where a probe had been driven to a 1 meter depth under an asphalt road, 4 liters (1 gallon) of Sun #6 had been injected, and the probe had been removed. The presence of the Sun #6 was faintly apparent on the recorder output. The success with the Sun #6 is probably due to the oil's high viscosity which gave a sharp interface with moisture in the soil.

#### 6.4.3 Technos, Inc.

The partial success with the subsurface radar at Saratoga led to the awarding of a small subcontract to Technos, Inc. of Miami, Florida. Technos has extensive

experience in subsurface radar and electromagnetic exploration of the earth to detect saltwater intrusion into freshwater reservoirs, to detect subsurface seepage of oil pollutants, etc.

The Technos study employed a small (900 MHz) antenna and two sandboxes 1 meter cubed in size with provisions for adding water or oil, to carefully investigate any radar pulse reflections at interfaces. Figure 6.11 shows the sandbox with the 900 MHz antenna on the surface of the sand. Notice the dark band in the middle third of the sandbox. This is oil-saturated sand; the top portion of the box is filled with dry sand, and the bottom is water-saturated sand.



Figure 6.11. Technos Sandbox Showing 900 MHz Antenna.

A small difference was found in wave travel time between dry sand and oil-saturated sand but the change between dry sand and water-saturated sand was much greater. A quite small change in reflected wave was found in layered samples such as that shown in Figure 6.11. The change was consistent for all samples, however, and computerized waveform analysis could perhaps give unambiguous results.

Some tests required that a 1.27 cm (1/2") OD copper tube be driven into the sand-box and oil forced from a series of holes in the tube. The presence of the tube masked any change in wave propagation due to oil in the sand.

#### 6.4.4 Ohio State University

OSU had a contract with EPRI to develop an optimized subsurface radar system for use by utilities in underground obstacle detection. OSU developed an orthogonal antenna arrangement (sending antenna at right angles to receiving antenna rather than using the same antenna for sending and receiving as GSSI does) that showed promise for reducing the effect of the pipe on the reflected wave patterns.

Discussions were held with OSU on possible tests of oil leaks with the orthogonal antenna and OSU's elaborate waveform analysis programs, but the equipment was not available during the leak location study.

#### 6.4.5 Summary---Subsurface Radar

The subsurface radar technique produced marginal results for oil spills alone. In all cases where tests were done in the presence of a cable pipe, the pipe masked any changes in reflected waveform due to the oil. If there is a discrete interface, such as where the watertable is above the cable pipe so that oil floats on the water, the system may work. Also, waveform processing to electronically eliminate the effect of the pipe may be a way to increase the resolution of the equipment.

## 6.5 RADIOACTIVE TRACERS

### 6.5.1 Principle

A short half-life, high gamma energy radioactive source added to the cable oil should exit at a leak and should be detectable from above ground, either directly through pavement or through shallow boreholes. Very sensitive instrumentation exists to detect low gamma emissions and the instrumentation is suitable for field use.

### 6.5.2 Preliminary Analysis of the System

A preliminary analysis showed that the use of radioactive tracers had technical promise, but there were several questions that needed addressing before an experimental evaluation could be considered. A subcontract was therefore given to Prof. D. R. Aulenbach, Radiation Physicist at Rensselaer Polytechnic Institute, to perform a thorough theoretical analysis of radioactive tracers for location of buried leaks.

The requirements for a tracer would be as follows:

1. A gamma emitter must be used; alpha and beta attenuation through the soil would be too great.
2. Attenuation even of gamma energy through the soil is high; a high level source must be used to give a chance of detection from ground level.
3. The radionuclide should have a half-life of 1/2 to 1 day. A compromise has to be made between the length of time needed by a crew, a crew has to find the leak once the radioactive material is injected into a pipe,

versus the length of time needed to allow decay of radioactivity in the soil to a level safe for workmen to enter the area and repair the leak.

4. The radionuclide must be compatible with the oil in the cable system.

Radioactive gases that were considered were radon 222, xenon 133, and krypton 85. None of these gases was as attractive as a liquid tracer.

Sodium 24 was chosen as the preferred radionuclide. The material has a 15 hour half-life and two gamma emissions of 1.38 and 2.76 Mev. It can be prepared in organic compounds that would be compatible with the cable oil.

Calculations showed that the radionuclide could be detected above ground for cables one meter deep or less. If cables were deeper, up to six meters, boreholes would probably have to be placed in the pavement.

The major problem occurred in the levels of radioactivity that would be seen outside the pipe. Suitably protected workmen could enter the trench to repair the leak within three days. If there were a leak of radioactively-traced oil into a basement, however, it would be three weeks before the basement could be entered.

This latter consideration caused enough concern for the radioactive tracer that no further work was done on the approach.

#### 6.5.3 Radioactive Microspheres

Later in the Leak Location program it was learned that Mr. Philip Lorio, Health Physics Officer at Columbia University, had worked with Phelps Dodge to make a proposal to Con Edison for investigation of radioactive microspheres for leak location. The approach had not been pursued and after discussions with PD and Con Ed, PTI gave a small subcontract to Mr. Lorio to pursue the concept further.

Microspheres are polystyrene or albumen beads that are produced in sizes from 5 to 50 micrometers diameter. They are tagged with a short half-life radioactive material and are injected into arteries to monitor blood flow and determine locations of blockages. The body absorbs or passes the microspheres. In theory, the tagged microspheres could be injected into a leaky section of cable pipe. Because of their extremely small diameter they should follow the oil flow due to the leak, and exit the pipe at the leak.

The earth should filter the microspheres, and they should therefore stay immediately adjacent to the cable pipe. Two advantages would result: the level of radioactivity at the leak should be higher (no spreading of the radioactive oil) and the "oil-in-the-basement" concern would be removed.

After an initial review showed the concept may be feasible, Mr. Lorio and PTI visited the appropriate New York State licensing agency to determine the requirements for applying this leak location method to leaks in unspecified sections of city streets. There appears to be no problem in obtaining the necessary license and injecting the microspheres in cable pipes providing that the following information is obtained and provided to the licensing agency:

1. Experimental proof that the soil does indeed filter the microspheres.
2. Determination of the concentration required for above-ground and bore-hole detection.
3. Insurance that the required amount of the radioactive material is below the Maximum Permissible Concentration for that material.

#### 6.5.4 Remaining Work

A fairly extensive experimental program is required to determine that the microspheres do exit at a leak, and to answer the questions raised by the licensing agency. The program would consist of:

1. Verify flow of untagged microspheres, to see if they stay in suspension long enough to reach a leak, and to determine if they exit the pipe at a leak.
2. Determine that cable backfill filters the microspheres, for a range of sphere sizes.
3. Using a realistic test apparatus, determine attenuation through backfill, concentration needed for tagged microspheres, effect of pavement, and specific detector needed.

#### 6.5.5 Summary--Radioactive Tracers

Tagging the cable oil with a radioactive isotope does not appear feasible because of concern that the oil might leak into an inhabited area.

Tagging microspheres with the radioactive material does have merit if it can be shown that the spheres flow with the oil and exit at a leak, and that the backfill filters the microspheres so that they stay in the cable trench.

There appears to be no problem obtaining the necessary license to use radioactive microspheres in city streets once several technical requirements are met.

## 6.6 EARTH ELECTRICAL RESISTIVITY

### 6.6.1 Principle

It is not uncommon to have several thousand liters of cable oil enter the ground before a leak is pinpointed. This oil may displace the far more conductive moisture in the soil and it was postulated that the area around the leak may have a higher electrical resistivity than surrounding soil.

Measurement of earth electrical resistivity is commonly done by utilities for determining the earth return path on overhead lines, and to monitor the condition of corrosion coatings on underground cables. A rapid and reliable means to measure changes in earth electrical resistivity along the cable route could provide a means for locating an oil leak.

### 6.6.2 Experimental Program

Southwest Research Institute (SwRI) had developed a sophisticated automatic earth resistivity data acquisition system for military use in detecting buried cavities. The system shown in Figure 6.12 consists of a pole-dipole resistivity array with current electrodes ten meters apart and potential electrodes one meter apart. An automatic control system sequentially scans the potential leads, and data are collected in a digital tape recorder. Later analyses of the data permit drawing of a two-dimensional cross section of the area of interest. Measurements with this system are rapid so it should be possible to scan a feeder route every few months, then look for changes in the resistivity profile upon indication of a leak.

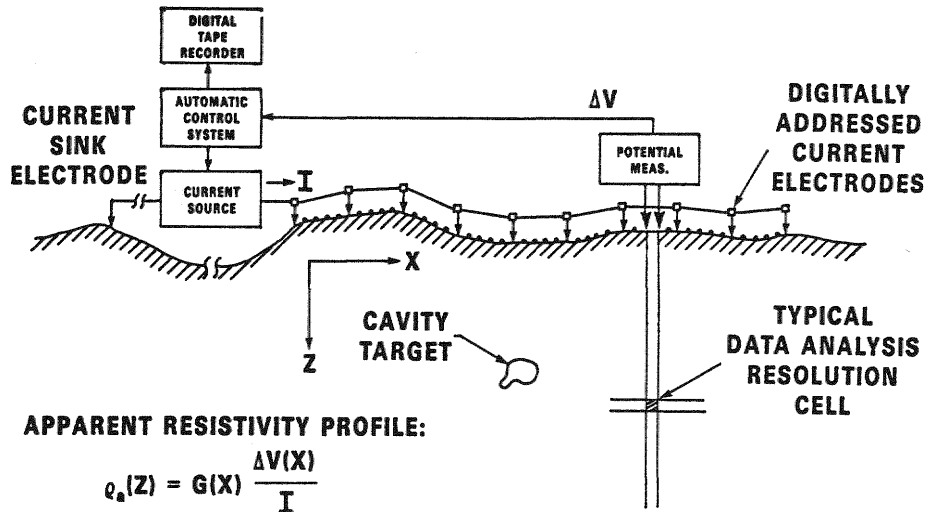


Figure 6.12. SwRI Automatic Earth Resistivity Data Acquisition System Layout.

A subcontract was given to SwRI to perform a brief theoretical and experimental analysis of this approach. A sample of typical controlled backfill was sent to SwRI, and arrangements were made for SwRI to obtain a large quantity of low viscosity polybutene.

Laboratory measurements were made with a polycarbonate cylinder 16.4 cm (6.5") diameter by 23.3 cm (9.2") long with stainless steel screen electrodes at either end. The controlled backfill, plus local San Antonio soil in another cylinder, was dried in the cylinder to 110 C until it reached a constant weight. Distilled water or oil was then introduced into the cylinder to reach the desired moisture or oil content. All measurements were made at 25 C.

AC resistance measurements were made at 100 Hz and 1, 10, 15 and 20 kHz to determine any effects that may be frequency related.

No resistivity changes could be found that could be related to the injection of oil into the cylinders.

Tests were done in a large open field with the system shown in Figure 6.12. A well point was used for injection of the polybutene as shown in Figure 6.13. Over 2000 liters (540 gallons) of low viscosity polybutene was injected into the earth from the well point.

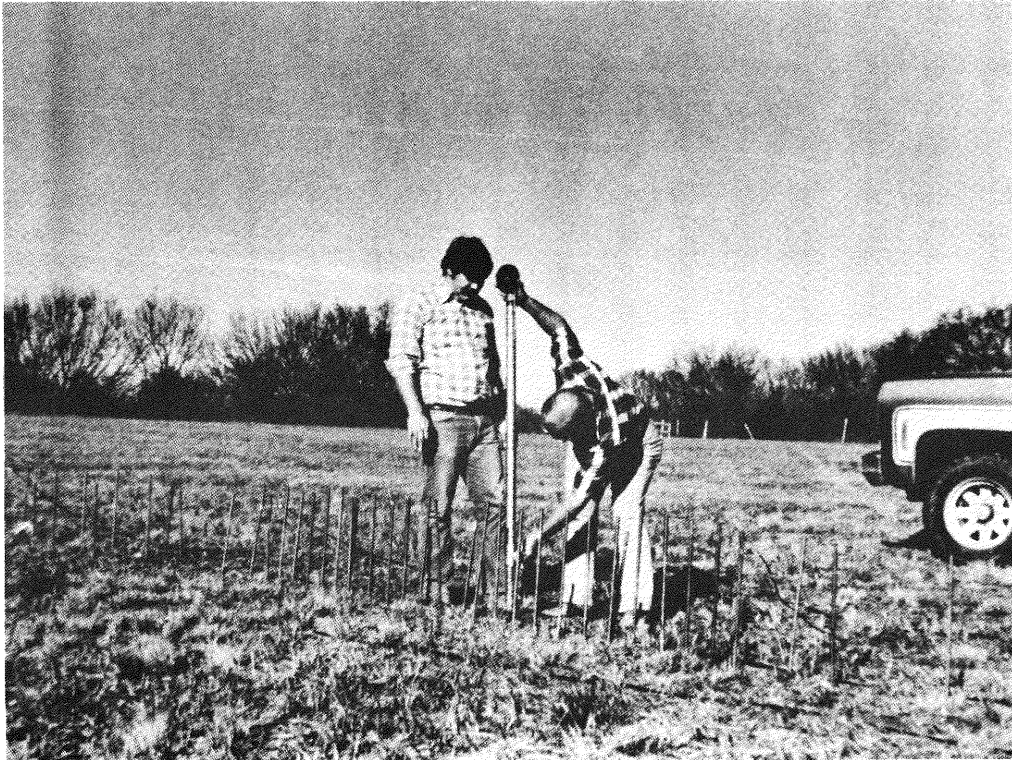


Figure 6.13. Field Setup for Resistivity Measurements.

No change in resistance could be found that could be traced to the presence of cable oil.

Further testing was done manually using a Wenner array identical to the type used by utilities. Variations in resistivity with time (and therefore with rainfall) were found in the area of the oil, but again no change could be attributed to presence of the oil.

### 6.6.3 Analysis

It had been anticipated that the cable oil would displace moisture in soil; evidently it did not. Even well compacted backfill has about 50% free space, which is usually occupied by water vapor and air. Since electricity is conducted through the soil water and dissolved salts from the soil, pore spaces and water movement are primary determinants of electrical resistivity. It appears that the oil merely filled the air space in the pores, and the moisture content---and hence the resistivity---was essentially unchanged.

### 6.6.4 Summary---Earth Electrical Resistivity

The presence of moderate quantities of cable oil in soil does not change the electrical resistivity enough to provide an indication of an oil leak. There is a chance that a very large quantity of oil, or disruption of moisture balance by a stream of high pressure oil from a leak, would create an anomaly. On balance, however, it does not appear that further work should be done on this method.

## 6.7 INFRARED ANALYSIS

### 6.7.1 Principle

Ambient earth temperature is usually less than 25 C while the oil temperature of an operating cable can be 45 C or so. It is possible that as warm oil leaves the cable pipe, a "halo" of warmed earth will be formed in the vicinity of the leak. Depending upon the thermal conductivity and diffusivity of the earth, presence of pavement, effects of other buried heat sources, etc. it may be possible to have a sensitive infra-red scan detect the imprint of this halo on the surface of the earth.

Oil pipeline companies have reported success in aerial surveys to detect leaks of heated oil from pipelines in arctic areas. The temperature differential there is more than 100 C, however, and the quantities of oil are far larger.

### 6.7.2 Experimental Program

The General Electric Company in Schenectady offers its Thermovision service with an Inframetrics infrared scanner capable of a 0.2 C resolution. The scanner output is to a portable TV screen with color capabilities to provide a temperature profile of the item being scanned.

Testing was conducted at the Saratoga site on a cool evening. An oil reservoir had been heated to 55 C and the heated oil was circulated in the concentric pipe assembly shown in Section 4, Figure 4.5. Approximately 40 liters/hour was leaked for four hours before the scan was done. The pipe was at a 1.2 meter depth with no pavement.

No temperature difference could be detected over the leak. The sensitivity of the equipment was verified when a small warm spot was noted on the ground surface near the leak. A partially filled-in borehole was found at that spot, left from earlier trials with the leak location dogs. Heat transfer from the leak through the approximately 60 cm (2') of soil and 60 cm of air in the borehole was sufficiently high that the earth temperature at the surface of the borehole was 2 C higher than the ambient earth.

A 60 cm (2') length of 25 cm (10") diameter steel pipe containing two 300 watt heating elements had been buried 91 cm (36") deep, and had been heated for several days. Thermocouples were placed on the pipe and at several points in the earth around the pipe. The evening of the test the pipe temperature was 40 C and the earth surface temperature was almost unchanged from ambient earth temperature. The IR scan showed no temperature elevation.

A 300 watt heating element had been buried 15 cm (6") deep in soil; the IR scan easily picked up the element and showed the earth temperature to be 150 C.

An early flow direction indicator attempt by Con Edison had heater elements placed on a joint casing, and thermocouples placed either side of the heaters. In theory, the downstream thermocouples would be slightly warmer due to heat carried by the flowing oil. The results had not been successful primarily because of lack of resolution in the test equipment. While the IR equipment was available at Saratoga, a 14 cm (5") pipe 6.1 m (20') long was filled with oil and connected to a variable speed pump. A heater element was placed at the center of the pipe, and the element was energized while an IR scan was conducted.

The downstream direction did show a slightly elevated temperature for a flow rate corresponding to a 38 liter/hour (10 gallon/hour) leak, but the results were not conclusive.

As a final test while the IR equipment was available, a scan was made of the acrylic joint casing (see Section 3) to observe temperature variations that may lead to natural convection currents. Figure 6.14 shows the IR scanning equipment in use on the casing. Surface temperature differences could be seen in the acrylic tubing, but it was not possible to observe temperature differences in the oil itself.

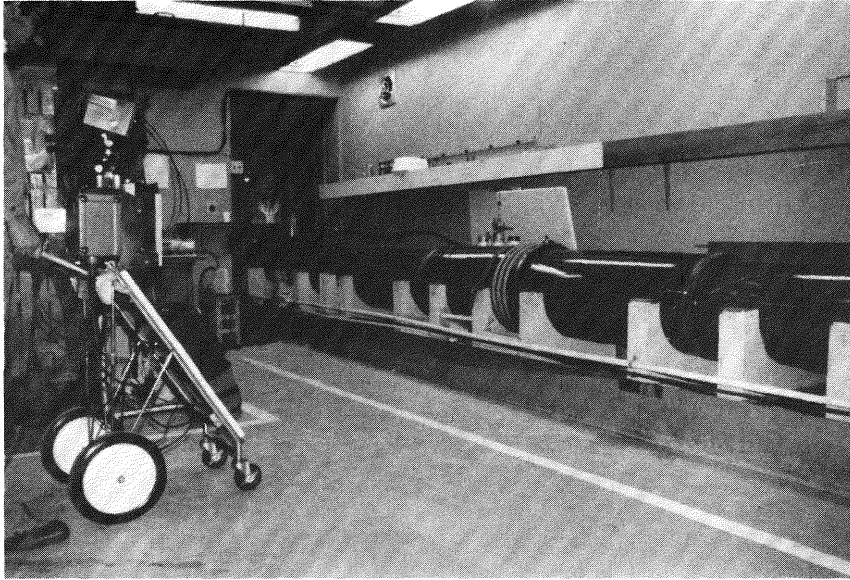


Figure 6.14. Infrared Equipment Used to Scan Temperature of Acrylic Joint Casing.

### 6.7.3 Summary---Infrared Scan

The infrared scan was not successful in locating a halo of warm oil around a leaking cable pipe in the controlled conditions at Saratoga, and it is unlikely that there would be success on a utility system.

## 6.8 MICROPHONY

### 6.8.1 Principle

Very sensitive microphones with appropriate filters and amplifiers are commonly used in location of leaks from buried water mains. The microphones pick up the audible hiss that is associated with high pressure water leaving the pipe---the frequency range is a few hundred Hertz compared to the 50 kHz and higher frequencies of acoustic emission.

### 6.8.2 Test Program

PTI had performed tests with microphonic equipment early in the leak location program, but had no success in determining the "hiss" due to an oil leak. Heath Consultants, Inc. has a good reputation in location of water leaks and had done some preliminary work with Con Edison seeking oil leaks. PTI observed successful water leak location efforts in the city of Albany, N. Y. The Heath equipment was much more sensitive than that used earlier, and Heath graciously agreed to conduct a demonstration at the Saratoga site where a number of buried leaks had been installed.

The Heath Aquascope was employed to look for several buried leaks under asphalt and in unpaved areas. In spite of the low level of background noise, moderate oil leaks of 77 liters/hour (20 gallons/hour) could not be detected at pressures of three atmospheres. Nitrogen was used to blow oil from the lines and the hissing sound of the nitrogen from the leaks was faintly detectable in the headphones.

One of the pipes was filled with water and pressurized to 3 atmospheres. The sound of the leaking water was very obvious through the Aquascope headphones.

### 6.8.3 Summary---Microphonics

Neither of the two trials of microphonic detection of oil leaks was successful. It has been postulated that the acoustic emission frequencies from a leak are sensitive to the shape of the hole in the pipe; the same is probably true for audible frequency hissing.

The viscosity of cable oil is far higher than that of water; it is likely that the amplitude of the hiss was less than for water, and that the frequency was different. The Aquascope has an electronic filter to pass the frequencies of about

100-500 Hz that are generated by a water leak. A test program could be developed to optimize the frequency response of the equipment for oil leaks, but the success with other leak location methods led to the abandoning of microphonics during this program.



## SECTION 7

### CABLE SYSTEMS OTHER THAN HPOF

#### 7.1 INTRODUCTION

The leak location study was concentrated on high pressure oil filled pipe type cables, the predominant cable type used by U. S. utilities, and the cable type that has the greatest susceptibility to large oil leaks.

Several of the approaches that were analysed during the program are also applicable to other transmission systems that may have leakage of dielectric fluid. The following sections summarize the approaches that should be taken for leak location on other transmission cables.

#### 7.2 SELF CONTAINED CABLE SYSTEMS

Hydraulic bridge methods can isolate a leak on a single conductor self contained cable system to about 2% of the length between stop joints, or to within about 50 meters. This system cannot be used on three conductor self contained cables. There, and on many single conductor cables, freezes can be performed quickly (after the cable is exposed) and the leak isolated fairly rapidly.

For self contained cables in duct systems, it is not uncommon to change a complete section between manholes so pinpointing the leak location is not critical. This is especially true for older cable systems, where other leaks may be expected to occur in the section.

Of the leak location methods investigated in the study, leak location dogs appear to be most suitable for self contained cables---especially for cables with low viscosity mineral oils and alkylbenzenes. It has been shown that a trained leak location dog can be taught to recognize a new oil odor in a couple of days so dogs presently used on HPOF cables should be suitable for self contained cables.

Tracer gases could also be considered but because of the low pressure operation and more intimate contact of the filling oil with the innermost tapes the gases that were shown to be suitable for HPOF cables may not be as attractive for self contained cables.

Both systems have the problem, however, that a leak in the inner pressure-retaining sheath may not evidence itself externally at that point, but may travel some distance under the outer jacket or sheath before finding a crack there.

Also, for self-contained cables installed in ducts it is likely that the oil, and tracer if used, will follow the duct for some distance so that even the most sophisticated instrument may give an incorrect indication of the leak location.

### 7.3 HIGH PRESSURE GAS FILLED CABLES

Several utilities operate high pressure gas-filled cable systems. These cables resemble HPOF systems but nitrogen at 15 atmospheres is the pressurizing fluid rather than oil. The cables are impregnated with a very high viscosity oil, and some of them have an outer sheath to keep the impregnating oil from draining from the cable over the years.

Addition of a tracer gas and searching for the gas with an electron capture detector is the ideal means for pinpointing a leak on a HPGF system. The tracer

will mix readily with nitrogen in any reasonable concentration and the entire nitrogen/tracer gas mixture can be purged at little cost if desired.

Quickly isolating the leak to a manhole section is not as straightforward for a HPGF system. The nitrogen flow direction indicator described in Section 3.7.4 is suitable only for large leak rates; the flow rate of the leaking gas is too small to measure for most leaks.

The preferable but time consuming method of determining direction of the leak is to add the tracer with the pressurizing gas at the filling location and monitoring its progress downstream at each manhole. That is, at the first manhole, sample the gas in the joint casing frequently until the tracer is found, then proceed to the next manhole, begin sampling again, etc. until a manhole is found in which no tracer appears. The leak is therefore between that manhole and the previous one.

Depending upon the leak rate, it could take twelve hours or more for the tracer to flow from manhole to manhole. The time needed for the tracer to pass from manhole to manhole can be calculated for a known leak rate, pressure, and distance between manholes. The time for diffusion of the tracer through nitrogen is very long compared to the leak rate for leaks that would be large enough for concern.

The process can be speeded by also injecting at the center manhole, or even every third or every other manhole, and carefully monitoring the time for the tracer to reach an adjacent manhole.

#### 7.4 SF<sub>6</sub> INSULATED CABLE

Compressed gas insulated transmission lines are ideal for tracer gas leak loca-

tion with a portable electron capture detector. The SF<sub>6</sub> gas itself is the best material for the tracer---as mentioned in Section 4, it is fifteen times better than C<sub>4</sub>F<sub>8</sub> for detection by the electron capture instrument.

Installations of SF<sub>6</sub> cables to date have been relatively short lengths so there is no need for a device to rapidly locate the general area of the leak.

The main problem in SF<sub>6</sub> leak location may be the presence of high background levels of the gas---either because the line terminates in an SF<sub>6</sub> substation or because enough gas is in the area due to the leak to saturate the instrument. The Ion Track Instrument and other good instruments have sensitivity selectors but it is still possible to saturate them so that they cannot be used for several minutes until they can be purged with clean, SF<sub>6</sub>-free air.

Refer to Sections 4.4 and 4.5 for photographs and a discussion of the preferred leak location methods and instruments.

It is recommended that less complex instruments commonly used for locating leaks in SF<sub>6</sub> circuit breakers, or even refrigeration stations, be used for a quick scanning of a cable line before the electron capture detector is employed.

SECTION 8  
LEAK LOCATION MANUAL

8.1 LEAK LOCATION MANUAL

One of the primary objectives of the leak location program was the preparation of a manual that would provide utilities with a detailed step-by-step procedure for leak location activities. It was to cover a range of leak conditions for each of the major types of underground transmission systems.

The manual has been prepared as a free-standing document and is attached to this report as Appendix C .

The manual consists of the following basic sections:

1. Verification that a leak exists.
2. Methods to reduce loss of fluid until leak can be found and repaired.
3. Means to rapidly isolate a leak to a short section of line.
4. Means to pinpoint the leak.
5. Comments on methods to repair the leak.
6. Restoration of the line to service.

Specific instructions are given on operation of the Enhanced Conductivity Oil probe and the electron capture detector. Suggestions are also provided for making most efficient use of leak location dogs.

General guidelines are offered; obviously each utility will have unique conditions that will require modification of the manual for best use by field crews.

## APPENDIX A

### MODEL FOR TRACER GAS DIFFUSION THROUGH SOIL

On one extreme the movement of tracer can be viewed as being governed by diffusion; on the other extreme, the leak is a jet orifice from which the tracer, together with the cable oil, is ejected. However, in the latter case one would expect that a pool of oil would form rapidly around the leak. If the tracer was originally under pressure in the oil, there will be large driving forces for mass transfer of tracer to the gaseous phase. This would be true even if the tracer had been present only at a particular equilibrium partial pressure, since it can be assumed that the concentration of tracer in the soil void spaces where a leak occurred would be essentially zero.

It may be possible therefore to view the migration of tracer to the surface as being radially outward in all directions, from the expanding oil pool. The value for  $P_{Ay}^*$  (Equation 1,) would be taken as a maximum, i.e. a value corresponding to the equilibrium vapor pressure. This value is needed for the equation shown in Figure 1 to calculate the flux rate to the surface. Also required is an effective diffusivity,  $D_e$ , that is, the diffusion coefficient in air modified to reflect soil conditions. Thus,  $D_e$  can be defined in terms of porosity,

$\epsilon$ , and tortuosity,  $\tau_h$ . Such values have been measured and reported (1-3). Some are given in Table 2 (1). The term  $h-y$  is probably not too critical if it is assumed that  $y$  changes little, relative to the change in surface area from which evaporation takes place. A sample calculation using this approach is given in Table 2.

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1. L.J. Thibodeaux (1979) Chemodynamics, Wiley-Interscience.
2. S. Lai, J.M. Tiedje, and A.E. Erickson (1976) In situ Measurements of Gas Diffusion Coefficients in Soils, *Soil Sci. Soc. Amer. J.*, 40, 3-6.
3. D.E. Rolston and B.D. Brown (1977) Measurement of Soil Gaseous Diffusion Coefficients by a Transient-State Method With a Time-Dependent Surface Condition, *ibid.*, 41, 499-505.

EQUATION 1

MODEL OF EVAPORATION AND DIFFUSION BETWEEN SOIL PORES

Leakage from the oil-filled cable produces an expanding pool from which the tracer gas desorbs (evaporates) and migrates.

$$\begin{aligned}
 n_A &= \text{rate of evaporation} = \text{rate of diffusion to surface} \\
 &\quad (\text{assuming no adsorption on soil or horizontal diffusion}) \\
 &= \frac{D_e}{h-y} (P_{Ay}^* - P_{Ai}) \quad (1)
 \end{aligned}$$

where

$$D_e = \text{effective diffusivity} = \frac{D_A \epsilon}{\tau_h}$$

$D_A$  = diffusivity of A in air

$\epsilon$  = porosity of soil

$\tau_h$  = tortuosity

$P_{Ay}^*$  = concentration of A within pores at evaporating plane

$P_{Ai}$  = concentration of A at air/soil interface

$h$  = depth from the surface to the pipe

$y$  = the vertical rise of the oil pool from the pipe surface

TABLE 1

Typical Data Soil type <sup>(1)</sup>	Particle Diameter, cm	Void Fraction, $\epsilon$	H
Sand	0.0147-0.0208	0.49	2.82
"	0.0208-0.0295	0.51	3.04
"	0.0417-0.0589	0.51	2.70
"	-	0.37-0.50	-
clay/silt	~ 50% < 0.0035	-	2.24
dry stream bed silt	~ 70% < 0.002	-	2.46
fresh stream bed silt	~ 50% < 0.002	-	1.58
granular, crushed rock	-	0.45	-
soil		0.43-0.54	-

$$H = \frac{\tau_h}{\epsilon} = \text{a hindrance factor}$$

TABLE 2

## SAMPLE CALCULATION (EQUATION 1)

$$\text{Assume } D_A = 0.2 \text{ cm}^2/\text{s} = 780.0 \text{ cm}^2/\text{hr}$$

$$h-y = 125 \text{ cm}$$

$$\epsilon = 0.5$$

$$H = 3$$

$$P_{Ai} = 0$$

$$D_e = \frac{D_A}{H} = \frac{720}{3} = 240 \text{ cm}^2/\text{hr}$$

From (1)

$$n_A = \frac{240 \text{ (cm}^2/\text{hr)}}{125 \text{ (cm)}} P_{Ay}^* \approx 2 \times P_{Ay}^*, \text{ ug/m}^2\text{-h if } P_{Ay}^* \text{ is in ug/m}^3$$

For He, assume  $P_{Ay}^* = 505 \text{ ppm}$

$$P_{Ai} = 5 \text{ ppm}$$

$$P_{Ay}^* - P_{Ai} = 500 \text{ ppm}$$

$$\text{ug/m}^3 = \frac{\text{ppm} \times \text{M.W.} \times 10^3}{24.5} = \frac{500 \times 4 \times 10^3}{24.5} = \frac{10^6}{24.5} = 4082 \text{ ug/m}^3$$

$$n_A = 2 \times 4082 \times 10^4 \text{ ug/m}^2\text{-h}$$

$$= 8.16 \times 10^7 \text{ ug/h which assumed release across a } 1 \text{ m}^2 \text{ surface.}$$

If one assumes the following:

release from surface is into an imaginary box of dimensions

$x, y, z$ , where  $x$  is the mean wind direction,  $u =$  mean wind.

Then the change in concentration in the box is given by

$$\frac{dC_A}{dt} = h_A C_{Ay} - uyz C_A$$

Integration yields

$$C_A = \frac{z_0}{z} C_0 \exp\left[-\frac{t}{x/u}\right] + \frac{n_A x}{uZ} [1 - \exp(-\frac{t}{x/u})]$$

TABLE 2 (CONT'D.)

Assume

$$C_0 = 41 \text{ ug/m}^3$$

$$z_0 = z = x = 0$$

$$t = 1 \text{ hr}$$

$$u = \text{windspeed} = 2 \text{ m/s} = 7200 \text{ m/h}$$

Under these conditions the exponential terms would be extremely small, then

$$C_A \approx \frac{n_A x}{uz} = \frac{n_A}{u}$$

The concentration of A would be

$$C_A = \frac{4082 \times 10^4 \text{ ug/m}^2\text{-hr}}{7200 \text{ m/hr}} = 567 \text{ ug/m}^3$$

i.e., a concentration that should be readily detectable above background.



APPENDIX B

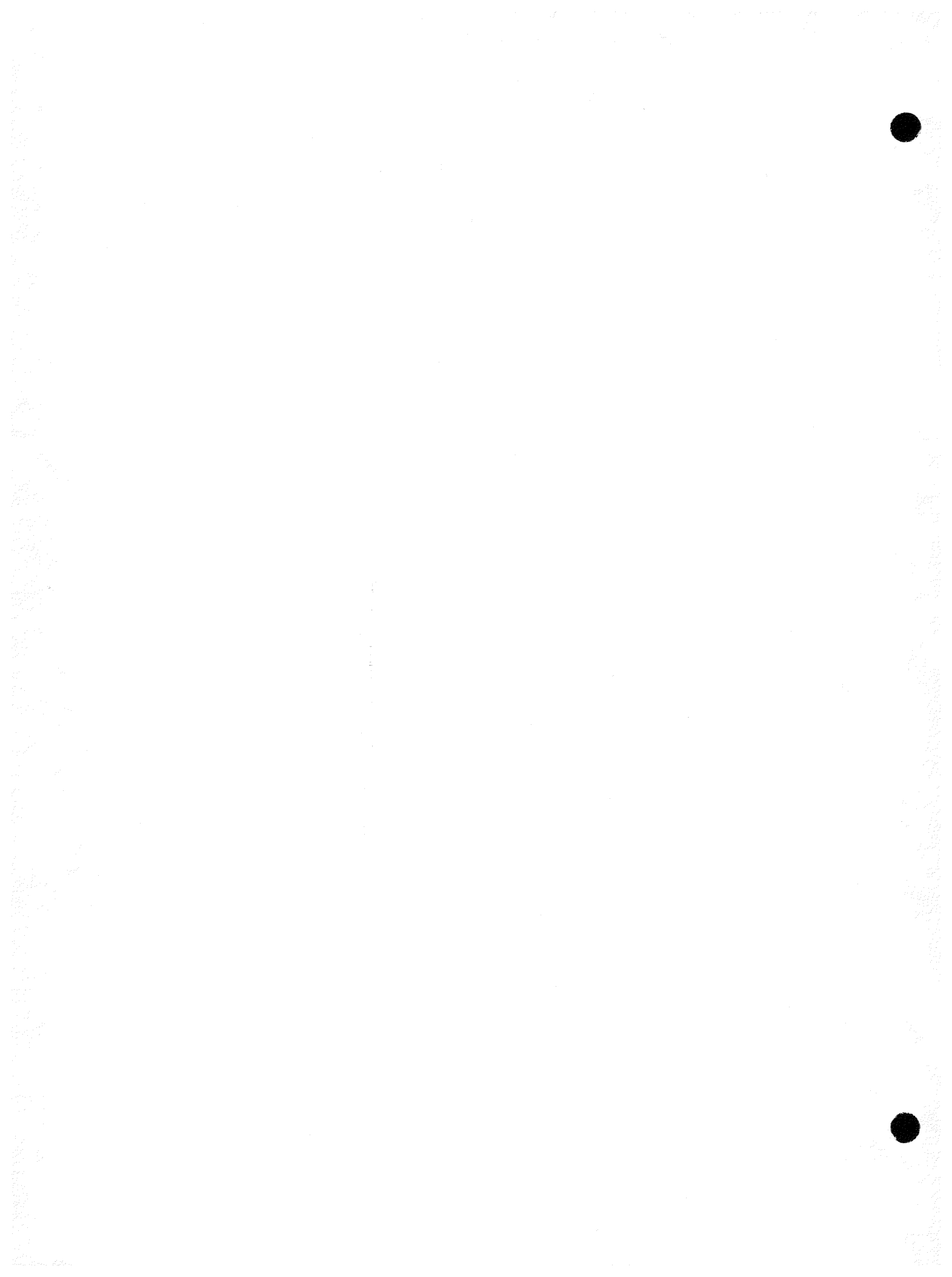
FINAL REPORT TO PTI

on

Evaluation of compatibility  
of tracer gases with oil paper  
cable

by Dr. Daniel Couderc

Institut de Recherche d'Hydro-Québec



EVALUATION OF COMPATIBILITY OF TRACER GASES WITH  
OIL PAPER CABLE

1.0 INTRODUCTION

Once a utility has determined that a leak exists in a HPOF cable circuit, either by monitoring oil level in the reservoir tank or by recording a too-frequent operation of pressurizing pumps, leak location operations begin. Assuming that it will not be possible to search for the cable oil alone, it will be necessary to add a detectable tracer gas to the oil. The preferable method is to have the tracer permanently in the oil. The drawback to this method of adding the tracer gas is that the utility must be certain that there is no long term degradation of electrical properties of the insulation due to the presence of the tracer.

The purpose of the study described in this report was to evaluate, through aging tests of cable models, the long term compatibility of tracer gases with HPOF cable insulation.

## 2.0 EXPERIMENTAL

### 2.1 Cable model construction

The main parts of a typical cable model used for the study are identified in Figure 1. One layer of duplex paper is applied, with a 1 mm overlap between adjacent turns, on the copper conductor 12.7 mm in diameter and 305 mm in length. Four layers of kraft paper tapes 25.4 mm wide and 124  $\mu\text{m}$  thick are then lapped under constant traction with a nominal registration of 35/65 and a 1 mm butt-gap. A single layer of 127  $\mu\text{m}$  thick tin foil applied over the insulation forms the low voltage electrode. The stress cones are clad with tinned copper wire which is insulated from the low voltage electrode by a small kraft paper ring. A completed sample is seen in Figure 2.

The cable models are built on the winding lathe shown in Figure 3. This lathe designed at IREQ especially for cable model construction allows one to accurately control the registration and the traction applied on the tapes. The stress cones are automatically wound with the required slope. These features guarantee a very good uniformity among the samples produced according a given set of parameters.

Loss tangent measurements were made with a three-electrode system combination with the stress cones earthed. A two-electrode system (stress cones and low voltage electrode at ground potential) was used for aging tests as well as corona and breakdown tests.

B-3

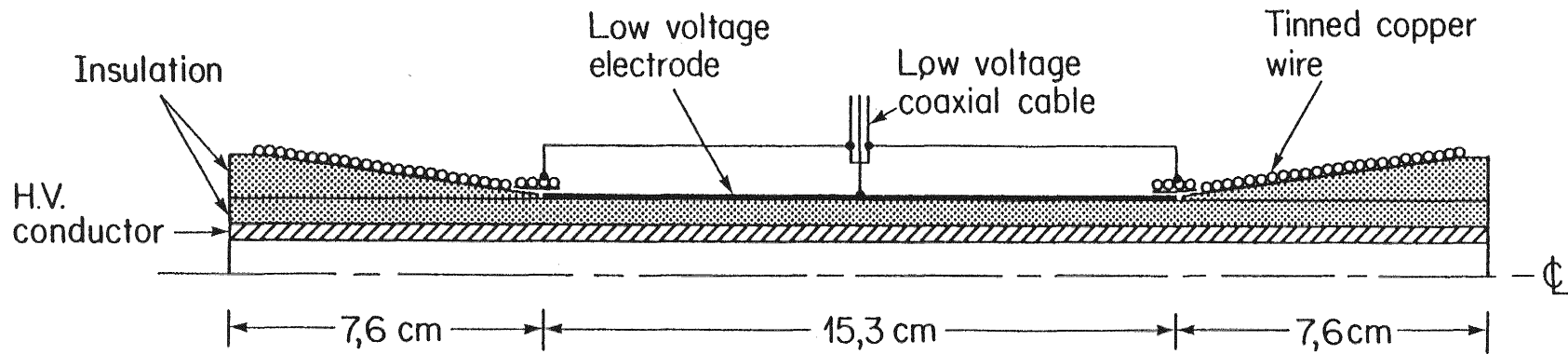


Figure 1: Schematic diagram of a cable model

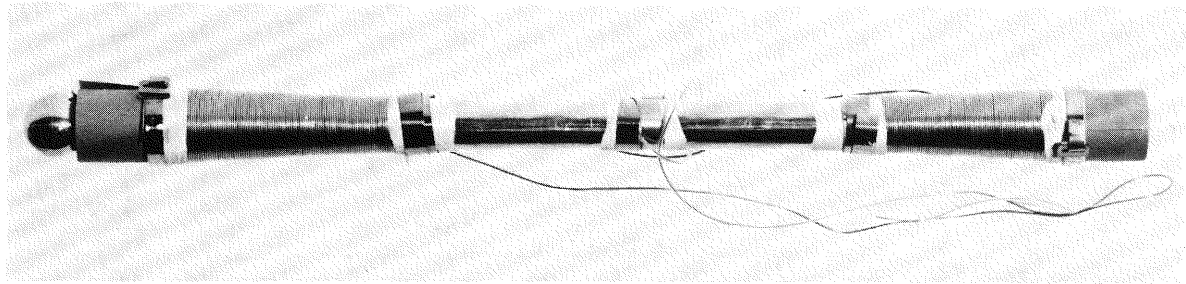


Figure 2: Completed cable model

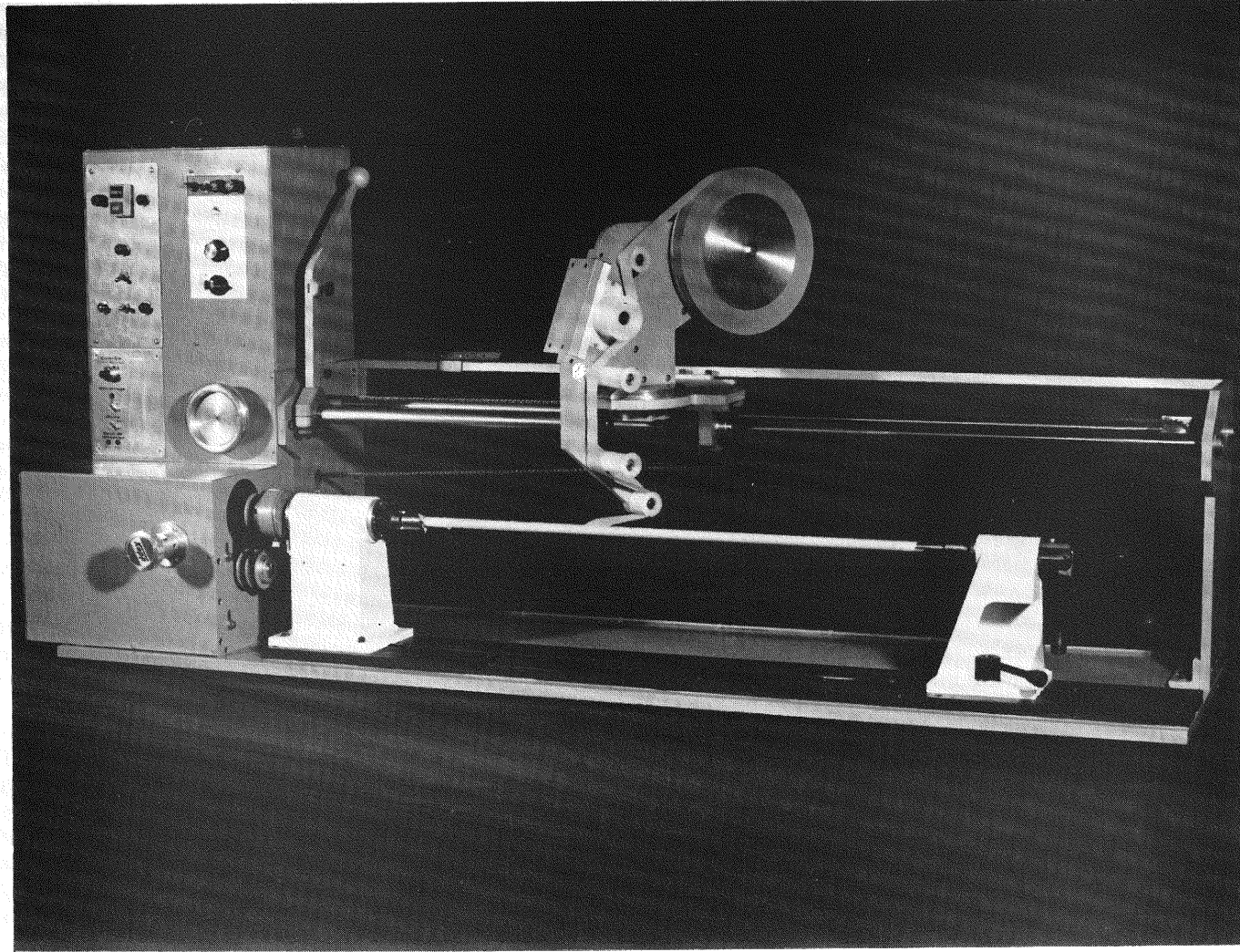


Figure 3: Lathe used for cable model construction

## 2.2 Apparatus for drying and impregnation of cable models

The apparatus shown in Figure 4 allows the simultaneous drying and impregnation of four models. The pumping system includes a sorption pump for rough pumping and for degasification of the impregnating fluid, and an ion pump for the drying of the cable models. Such a pumping system allows the apparatus to stay free of any contaminating oil vapors. Each basic module of the glassware consists of three cylinders. Fine droplets of oil coming from the top feeding cell kept at 100°C enter the first cylinder in which a vacuum of 0.65 Pa is maintained. The oil is again finely divided in its transfer to the second cylinder where the same vacuum and temperature (100°C) conditions are maintained. While the oil is being degassed, the sample is vacuum dried in the third cell at 110°C and under a vacuum of  $1.3 \times 10^{-3}$  Pa. The degassed oil is then slowly transferred to the impregnating cells where the temperature and vacuum have been adjusted to the temperature and vacuum existing in the oil degassing cylinders. When the impregnation is completed, the pressure above the oil is brought back to 101 kPa with dry nitrogen.

## 2.3 Test conditions

The following test conditions were observed:

1. Duration of test: 750 hours
2. Temperature: 120°C
3. Electrical stress: 15.8 kV/mm (400 V/mil)
4. Frequency: 60 Hz

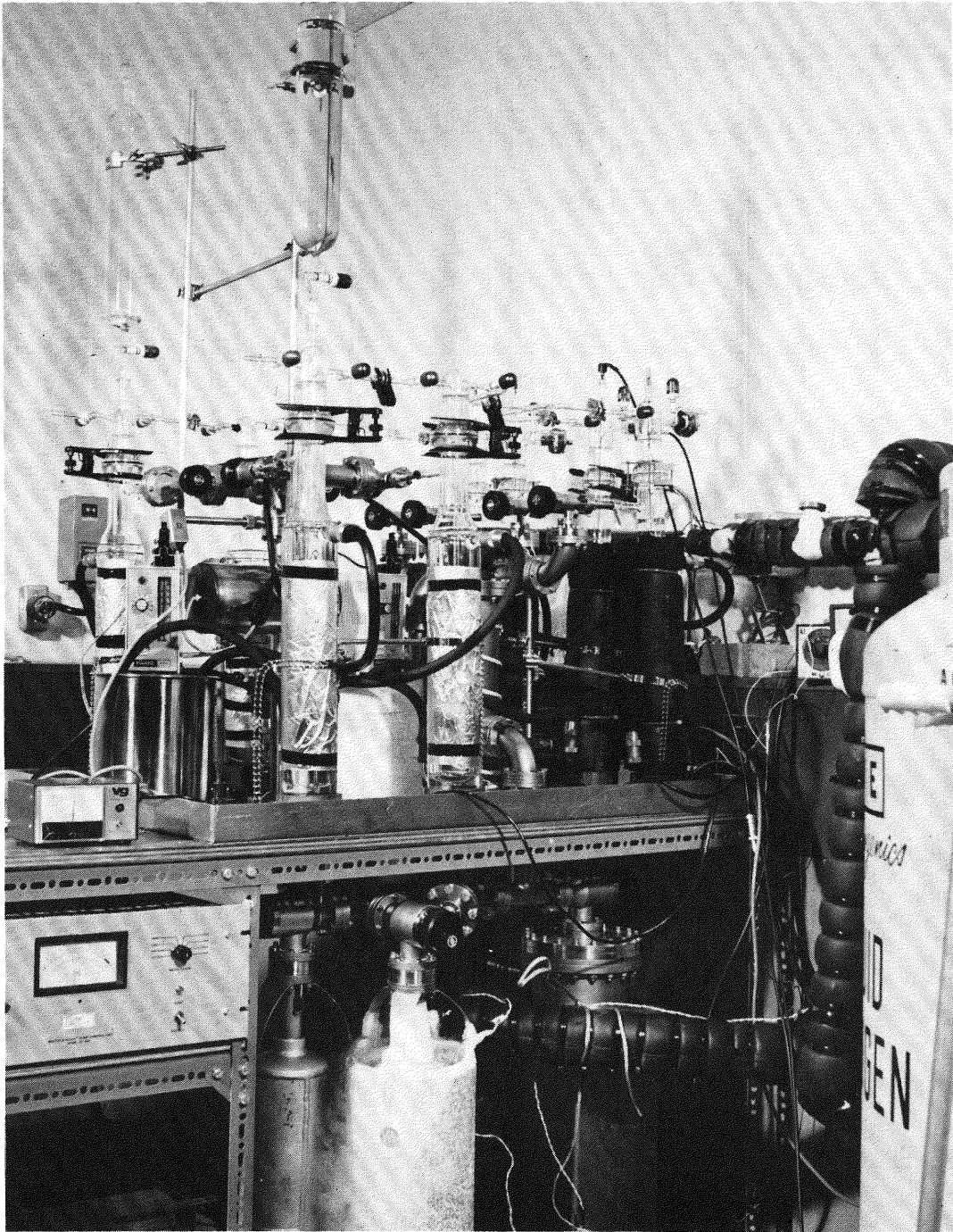


Figure 4: Cable model impregnating apparatus

5. Oil: blend of 70% of low viscosity polybutene mixed with 30% of Sun XX, (proportions similar to those found in a cable pipe)
6. Paper: good quality kraft paper 124  $\mu\text{m}$  thick with a density of 1.02  $\text{g}/\text{cm}^3$
7. Level of contaminants added:
  - a) Moisture: 0.1% moisture in paper
  - b) Oxygen: 3.6 ml/liter
  - c) Copper: 4 ppm copper octalate
8. Tracer concentration: at saturation pressure of 238 kPa
9. Tracer gases:
  - a) He
  - b)  $\text{N}_2$
  - c)  $\text{CF}_4$
  - d)  $\text{SF}_6$
  - e)  $\text{c-C}_4\text{F}_8$

A.C. breakdown test was done at 85°C on every model at the end of aging. Also, as a control, unaged cable models pressurized with  $\text{N}_2$  tracer gas were tested for a.c. breakdown at 85°C.

#### 2.4 Test cells

Two types of cells were designed for the test. They are made of borosilicate glass with a glass to metal joint to connect the stainless steel gas line. The cell shown on the right of Figure 5 can be pressurized up to 342 kPa while the left cell must have its top part mechanically held to prevent it from slipping out with a pressure build up. The

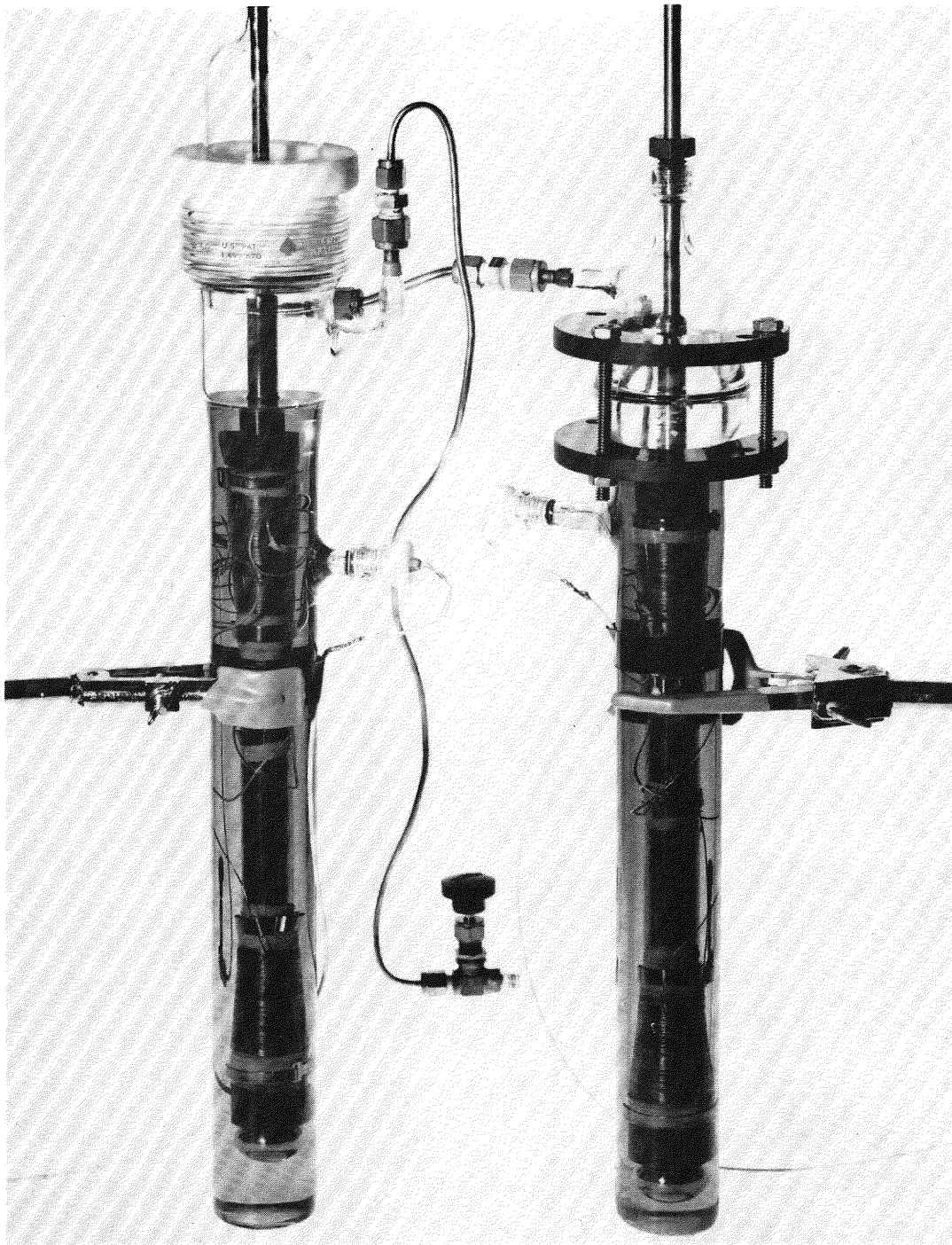


Figure 5: Test cells for aging and a.c. breakdown tests

high voltage connection is made with a copper rod going through the cell top and the low voltage connections are made with a Teflon coaxial cable going through the side wall of the cell. All the feedthrough parts and o-rings in contact with the oil are in Teflon.

## 2.5 Test equipment

The ventilated oven used for the aging has a capacity of 0.16 m<sup>3</sup> and can hold up to 20 cells. With such a load the temperature set at 120°C was measured in six different locations inside the oven with a maximum difference of less than ± 0.4°C.

The loss tangent measurements were performed with a high voltage capacitance bridge Guildine model 9910 and corona measurements were taken using a Biddle partial discharge detector system at the minimum detection sensitivity of 1 pC.

## 2.6 Experimental procedure

After impregnation the cable model is transferred rapidly to the test cell which has been previously filled with oil. This oil was filtered and degassed in a separate apparatus and the contaminants injected in the oil with a syringe after the degasification process. The pressure was then brought back to atmospheric with the chosen tracer gas. With the cable model properly connected to the coaxial cable, the test cell was sealed and pressurized with the tracer gas slightly above the atmospheric pressure. Each sample was exposed approximately two minutes to the ambient air during its transfer from the impregnating cell to the test cell.

The cable models were tested for corona at the aging electrical stress to detect any connection problems, or imperfect impregnation. A discharge level  $\leq 1$  pC was considered as acceptable. Loss tangent and capacitance were also measured at 1 kHz and at room temperature for every model as part of the quality check-up of the samples before their installation in the oven.

The cable models were installed in the oven as illustrated in Figure 6. All gas lines and low voltage electrical connections are going through a two inch diameter hole on the left side of the oven. High voltage is supplied by a feedthrough to a top plate on which all the center conductors of the models are connected. The cells pressurized with the same tracer gas are connected in series with the gas supply and a single gauge monitors the pressure in each main gas line.

The aging test was started as follows:

1. The temperature is set to 120°C. Gas pressure is monitored during the oil expansion to avoid damage to the cell.
2. When temperature is stabilized ( $\sim 12$  h) gas pressure is gradually increased up to the specified value.
3. Voltage is applied at half its specified value for 12 hours and measurement of  $\tan \delta$  is made.
4. Full voltage is applied to the samples at  $t = 0$  of the aging period. The first  $\tan \delta$  measurement at full voltage is made at  $t = 4$  h to allow the stabilization of the  $\tan \delta$  values which are decreasing rapidly following voltage application.

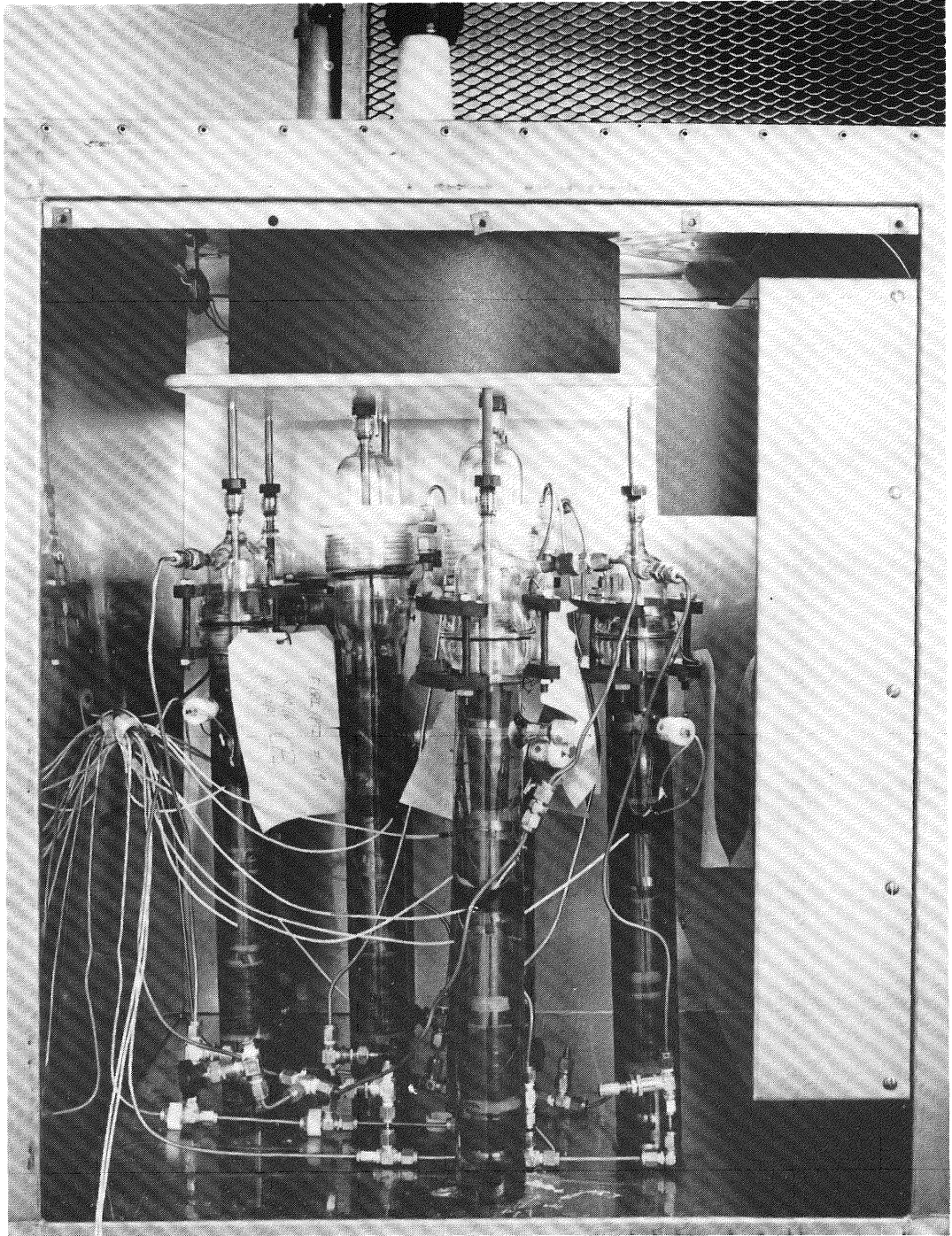


Figure 6: Installation of cable models in the oven for aging test

### 3.0 TEST RESULTS

#### 3.1 Aging test 1

Two aging tests were performed. The first test involved the aging of ten cells with  $N_2$  (two samples),  $CF_4$  (four samples) and  $c-C_4F_8$  (four samples) as tracer gases. The temperature was stabilized at  $120^\circ C$  during the first 96 hours with the full voltage (9 kV) applied intermitently until the cause of strong partial discharges in the oven was found: a  $CF_4$  sample had one low voltage platinum wire feedthrough broken with the result of a high potential on the wire end. The voltage was removed from this model and the aging was resumed with the remaining nine models. The tenth model stayed in the oven to be thermally aged over the same time period.

Results of the test are tabulated in Table 1 and the  $\tan \delta$  vs time curves of the samples pressurized with  $N_2$ ,  $CF_4$  and  $c-C_4F_8$  are depicted in Figures 7, 8 and 9 respectively. The losses of all models had approximately the same level of 0.5% at the starting point. This level increases regularly and at a rather slow rate (except model No. 4,  $CF_4$ ) until the 335 h point was reached. Between 335 h and 504 h the losses of the two  $N_2$  samples sharply increased to reach values of 5 and 5.4%. This very high level of losses may be explained by the fact that the two models had briefly seen, by accident, a voltage near the breakdown level of the insulation during preliminary tests. Although corona tests following the incident, did not reveal any damage to the insulation, it is possible that the models has suffered somehow from the overvoltage. An

TABLE 1  
TAN  $\delta$  AND  $\epsilon'$  OF CABLE MODEL INSULATION UNDER AGING\*

Aging time		96 h		168 h		336 h		504 h		675 h	
Gas	Model No.	$\tan \delta$ (%)	$\epsilon'$	$\tan \delta$ (%)	$\epsilon'$	$\tan \delta$ (%)	$\epsilon'$	$\tan \delta$ (%)	$\epsilon'$	$\tan \delta$ (%)	$\epsilon'$
N <sub>2</sub>	1	0.55	2.9	0.67	3.0	0.81	3.0	5.03	3.1	6.55	3.2
	2	0.46	3.0	0.50	3.0	0.66	3.0	5.40	3.2	6.24	3.4
CF <sub>4</sub>	3	0.53	3.1	0.61	3.1	0.72	3.1	1.67	3.2	2.70	3.3
	4	0.64	3.1	0.69	3.2	1.12	3.3	3.55	3.6	4.48	3.7
	5	0.58	3.1	0.64	3.2	0.76	3.2	1.28	3.3	2.99	3.4
c-C <sub>4</sub> F <sub>8</sub>	6	0.63	3.1	0.64	3.2	0.72	3.2	0.88	3.2	1.27	3.3
	7	0.62	3.0	0.68	3.1	0.87	3.1	1.15	3.1	1.49	3.1
	8	0.55	3.1	0.59	3.2	0.79	3.2	0.94	3.3	>10	3.4
	9	0.57	3.0	0.55	3.1	0.64	3.1	2.04	3.2	4.00	3.5

\* Aging parameters: Temperature : 120°C  
 Pressure : 238 kPa  
 Electrical stress: 15.8 kV/mm  
 Frequency : 60 Hz

N.B.:  $\epsilon'$  data are calculated

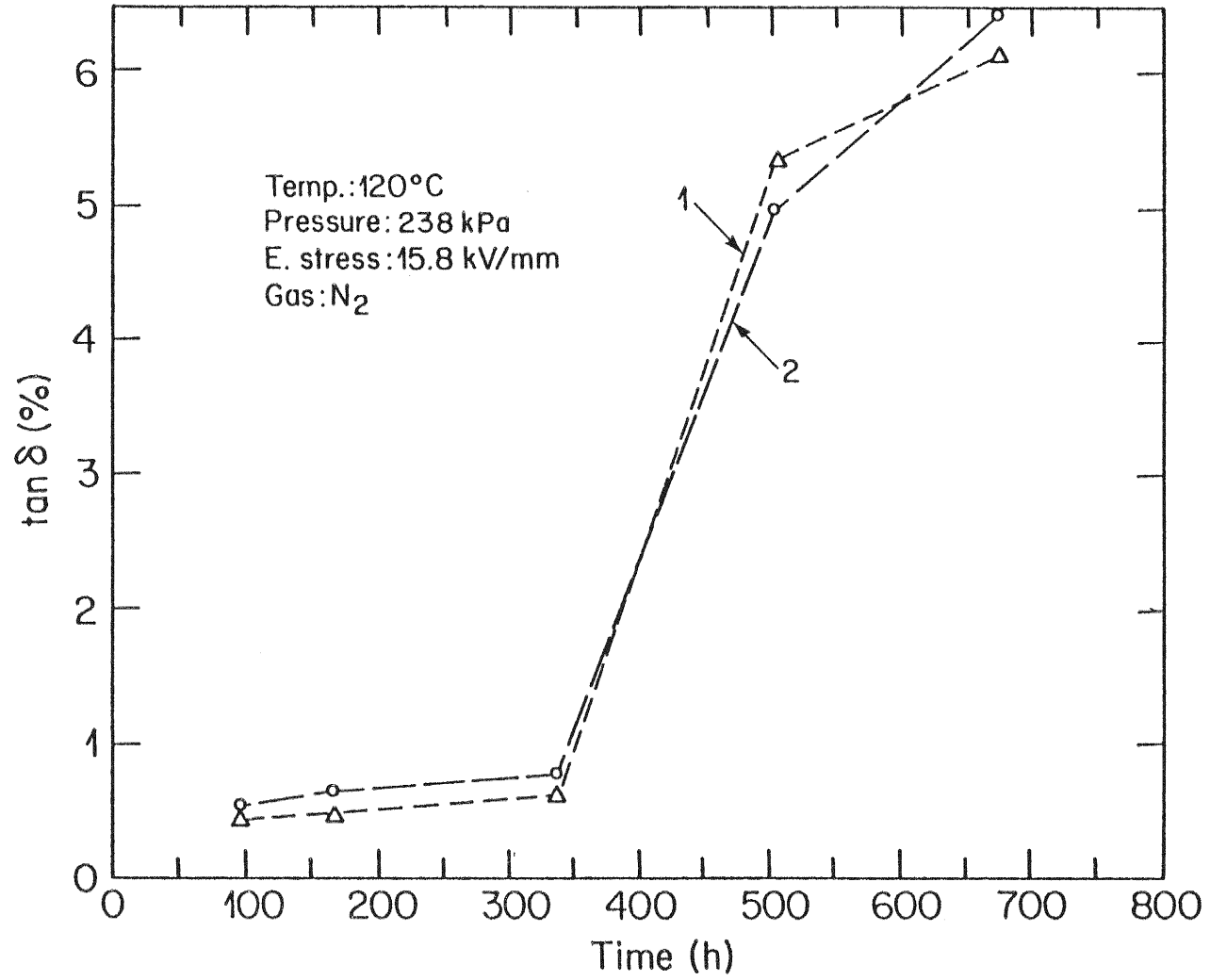


Figure 7: Tan  $\delta$  vs time at cable models pressurized with N<sub>2</sub> tracer gas

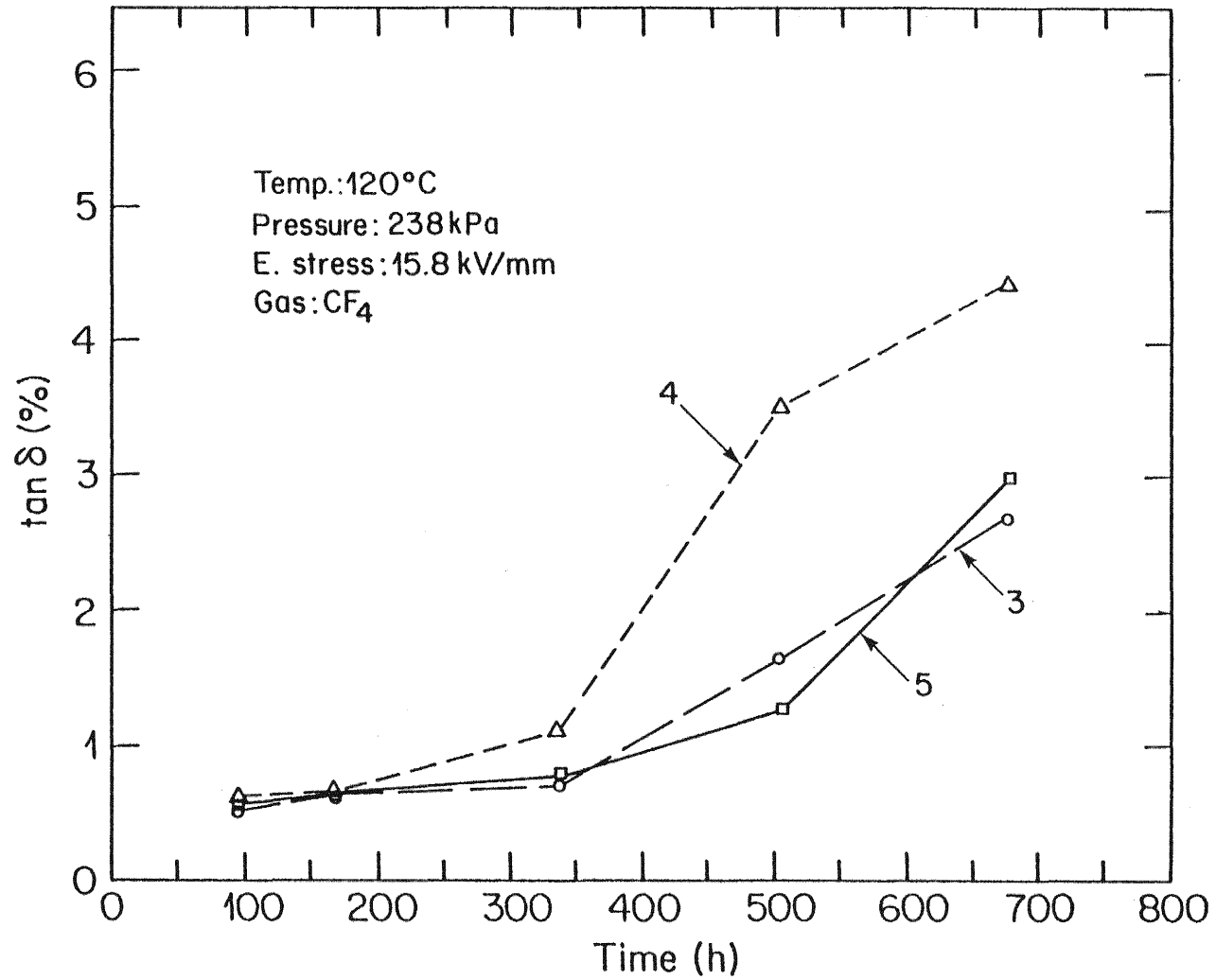


Figure 8: Tan  $\delta$  vs time of cable models pressurized with CF<sub>4</sub> tracer gas

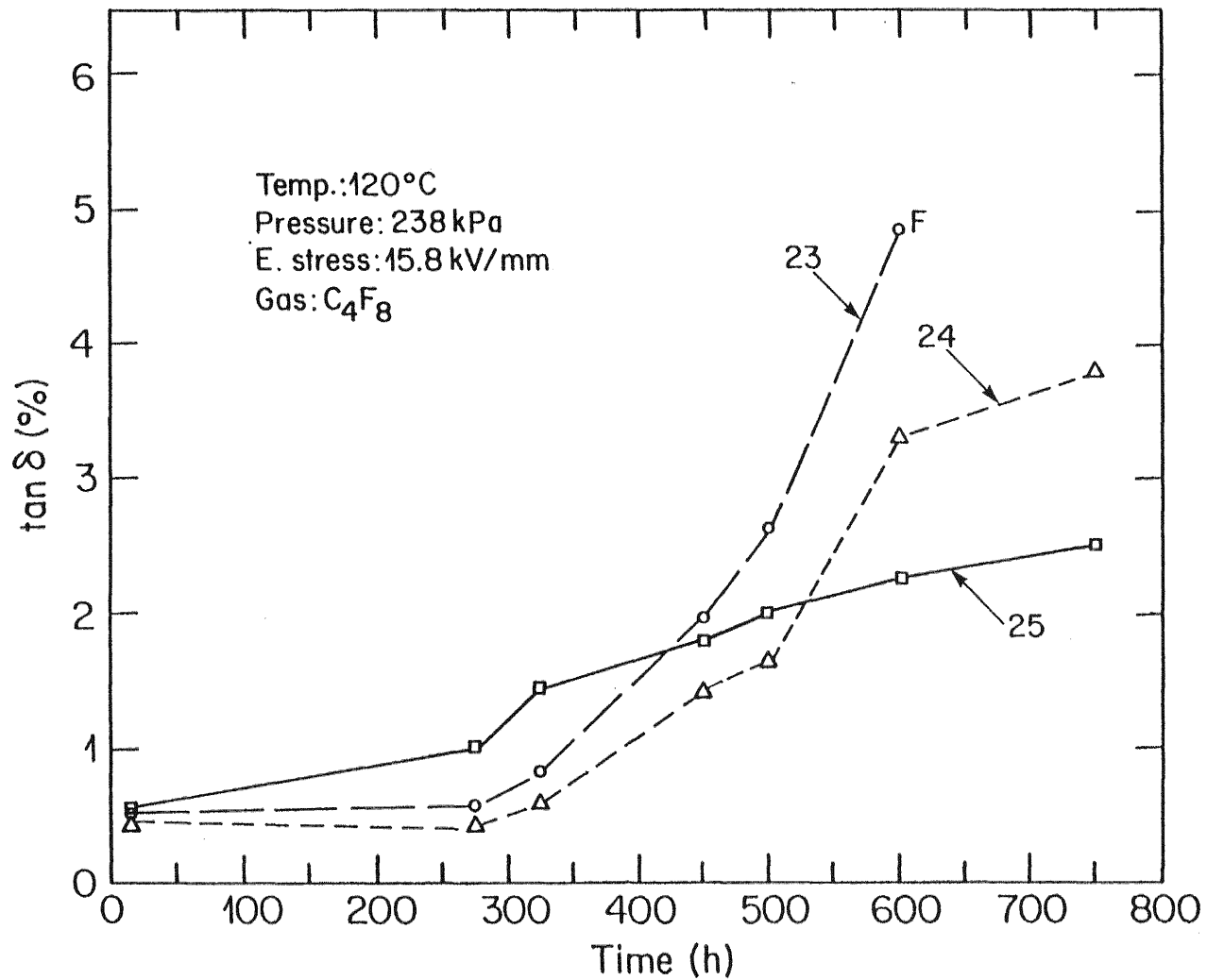


Figure 9:  $\tan \delta$  vs time of cable models pressurized with  $c\text{-C}_4\text{F}_8$  tracer gas

induced weakness in the insulation might have triggered the formation of high intensity partial discharges with, as a consequence, a sharp increase in the dielectric losses.

One can see that the rate of increase of  $\tan \delta$  for the  $\text{CF}_4$  models (Figure 8) becomes also higher between 336 and 504 hours. The behavior of the three samples is similar over the aging period, with however sample No. 4 showing a larger increase of  $\tan \delta$  with time.

Only one cable model (No. 9) among the four  $\text{c-C}_4\text{F}_8$  samples had a sudden increase of  $\tan \delta$  after the 335 hours point. After 675 h of aging this model showed a  $\tan \delta$  of 4%. The remaining three samples behaved similarly until the 504 hours mark after which sample No. 8 developed strong-partial discharges.  $\tan \delta$  was  $> 10\%$  at 675 hours and consequently the sample was considered as having failed. Samples No. 6 and 7 apparently did not develop any problem throughout the aging and finished the test with  $\tan \delta$  values of 1.27% and 1.49% respectively.

The overall high level losses shown by all the cable models was the main factor in the decision to stop the aging at 675 hours instead of 750 hours. Since the  $\tan \delta$  of the unaged models were uniformly higher than normally expected an investigation was done on the oil that was supplied to our laboratory for the test. The losses of the polybutene oil at  $100^\circ\text{C}$  were found to be 3%, result that we identified as the main factor of the contamination problem encountered with the samples. The dielectric losses of the dry paper were later measured at a level of 0.23% at  $100^\circ\text{C}$  which indicates that the paper did not contribute significantly to the

measured  $\tan \delta$  of the samples. A second aging test was then decided using new oils and the same paper.

### 3.2 Aging test 2

Two gases, namely He and SF<sub>6</sub>, were added to the previous three gases of aging test 1. New polybutene and Sun XX oils were tested upon reception. The power factors at 100°C of the polybutene and the Sun XX were 3.7% and 0.2% respectively. The physical aspect of the Sun XX oil was very different from the first shipment: higher viscosity and very dark brown color. Although the power factor of this oil was somehow higher than the specified value of 0.06% it was decided to use it since the oil blend used in the test cells contains only 30% of Sun XX. The polybutene oil, however, had to be cleaned. It was filtered at 110°C under vacuum through fuller's earth heated at the same temperature. A medium grit fritted glass disc separated the earth from the clean oil container. The average  $\tan \delta$  value of the cleaned polybutene oil obtained was 0.04% at 100°C. The 70% polybutene - 30% Sun XX blend used for impregnation and as filling oil has a power factor of 0.12%

After impregnation of a typical cable model the power factor of an oil sample extracted from the impregnating cylinder was 0.16%. The filling oil, with the contaminants added had a power factor of 0.28%. Two of the unaged samples with the filling oil not contaminated, used as a control, were also tested for dielectric losses. Their  $\tan \delta$  values were 0.31 and 0.30% at 85°C, and also 0.59 and 0.49% at 120°C.

The aging test results are tabulated in Table 2 while the curves of  $\tan \delta$  vs time for tracer gases He, N<sub>2</sub>, CF<sub>4</sub>, SF<sub>6</sub> and c-C<sub>4</sub>F<sub>8</sub> are shown in Figures 10 to 14 respectively.

1. He (Figure 10): The three samples failed before the end of the test. The sample No. 11 had losses higher than 10% after 275 hours and it was consequently deenergized. Losses of samples 10 and 12 were also high (4.6% and 4.9%) and shortly after the measurements voltage had also to be removed when strong discharges were tripping the H.V. power supply off. Many bubbles were observed coming out from the three cable models, still pressurized, after voltage removal.

2. N<sub>2</sub> (Figure 11): The behavior of the three samples was very similar until the 450 h mark. From that point to the end of aging the models separated one from the other with samples 14 and 15 having a steep increase in  $\tan \delta$  while the losses of sample No. 13 augmented at a lower rate.

3. CF<sub>4</sub> (Figure 12): Samples 16, 17 and 18 followed each other very closely throughout the test although they ended with the high loss level of 4.7%. As seen with previous tracer gases  $\tan \delta$  starts to increase more rapidly after 300 hours of aging.

4. SF<sub>6</sub> (Figure 13): Cable models Nos. 19 and 21 failed between 275 and 325 hours, while No. 20 failed between 325 and 450 hours. A non aged cable model kept on stand-by was then pressurized with SF<sub>6</sub> and installed in the oven at the 325 h mark when samples 19 and 21 were removed. The new sample (No. 22) went through the remaining of the test with a steady but relatively moderate increase of the dielectric losses to reach a  $\tan \delta$  of 1.38% after being aged for 425 hours.

TABLE 2

TAN  $\delta$  AND  $\epsilon'$  OF CABLE MODEL INSULATION UNDER AGING\*

Aging time		25 h		275 h		325 h		450 h		500 h		600 h		750 h	
Gas	Model No.	$\tan \delta$ (%)	$\epsilon'$	$\tan \delta$ (%)	$\epsilon'$	$\tan \delta$ (%)	$\epsilon'$	$\tan \delta$ (%)	$\epsilon'$	$\tan \delta$ (%)	$\epsilon'$	$\tan \delta$ (%)	$\epsilon'$	$\tan \delta$ (%)	$\epsilon'$
He	10	0.50	2.9	4.62	3.0	F	-	-	-	-	-	-	-	-	-
	11	0.47	3.1	>10	3.2	F	-	-	-	-	-	-	-	-	-
	12	0.49	3.0	4.91	3.1	F	-	-	-	-	-	-	-	-	-
N <sub>2</sub>	13	0.53	3.2	0.59	3.3	0.87	3.3	0.81	3.4	0.96	3.4	1.12	3.4	1.51	3.4
	14	0.54	3.1	0.63	3.2	0.92	3.2	0.88	3.3	1.11	3.3	2.06	3.3	3.66	3.3
	15	0.51	3.3	0.61	3.4	0.85	3.4	0.84	3.4	1.24	3.4	2.15	3.5	4.32	3.5
CF <sub>4</sub>	16	0.47	3.1	0.58	3.2	0.73	3.2	1.19	3.2	2.03	3.3	3.37	3.3	4.76	3.4
	17	0.64	3.0	0.55	3.1	0.69	3.1	1.28	3.2	2.06	3.2	3.26	3.3	4.75	3.3
	18	0.53	3.2	0.53	3.3	0.67	3.3	1.14	3.4	1.97	3.4	3.29	3.5	4.75	3.5
SF <sub>6</sub>	19	0.52	3.2	2.58	3.3	F	-	-	-	-	-	-	-	-	-
	20	0.54	3.2	0.69	3.2	0.96	3.2	F	-	-	-	-	-	-	-
	21	0.54	3.0	4.30	3.2	F	-	-	-	-	-	-	-	-	-
	22					0.63	3.1	0.96	3.2	0.95	3.2	1.08	3.2	1.38	3.2
c-C <sub>4</sub> F <sub>8</sub>	23	0.51	3.2	0.56	3.3	0.81	3.3	1.98	3.4	2.64	3.4	4.86	3.5	F	-
	24	0.48	3.3	0.47	3.4	0.62	3.4	1.45	3.4	1.65	3.5	3.33	3.5	3.84	3.5
	25	0.52	3.2	1.05	3.2	1.47	3.2	1.81	3.3	2.03	3.3	2.28	3.3	2.49	3.3

\* Aging parameters: Temperature : 120°C  
 Pressure : 238 kPa  
 Electrical stress: 15.8 kV/mm  
 Frequency : 60 Hz

N.B.:  $\epsilon'$  data are calculated

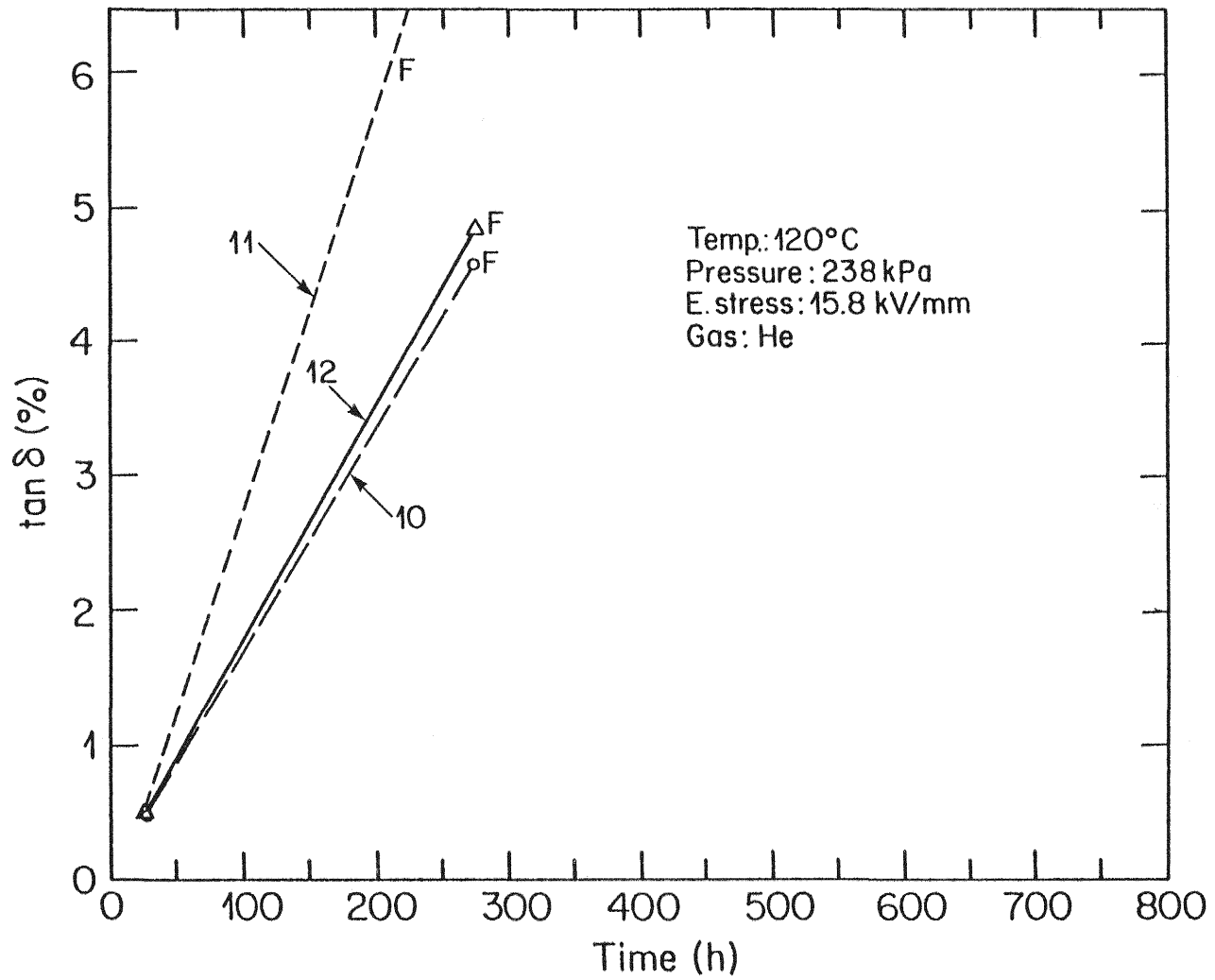


Figure 10: Tan  $\delta$  vs time of cable models pressurized with He tracer gas

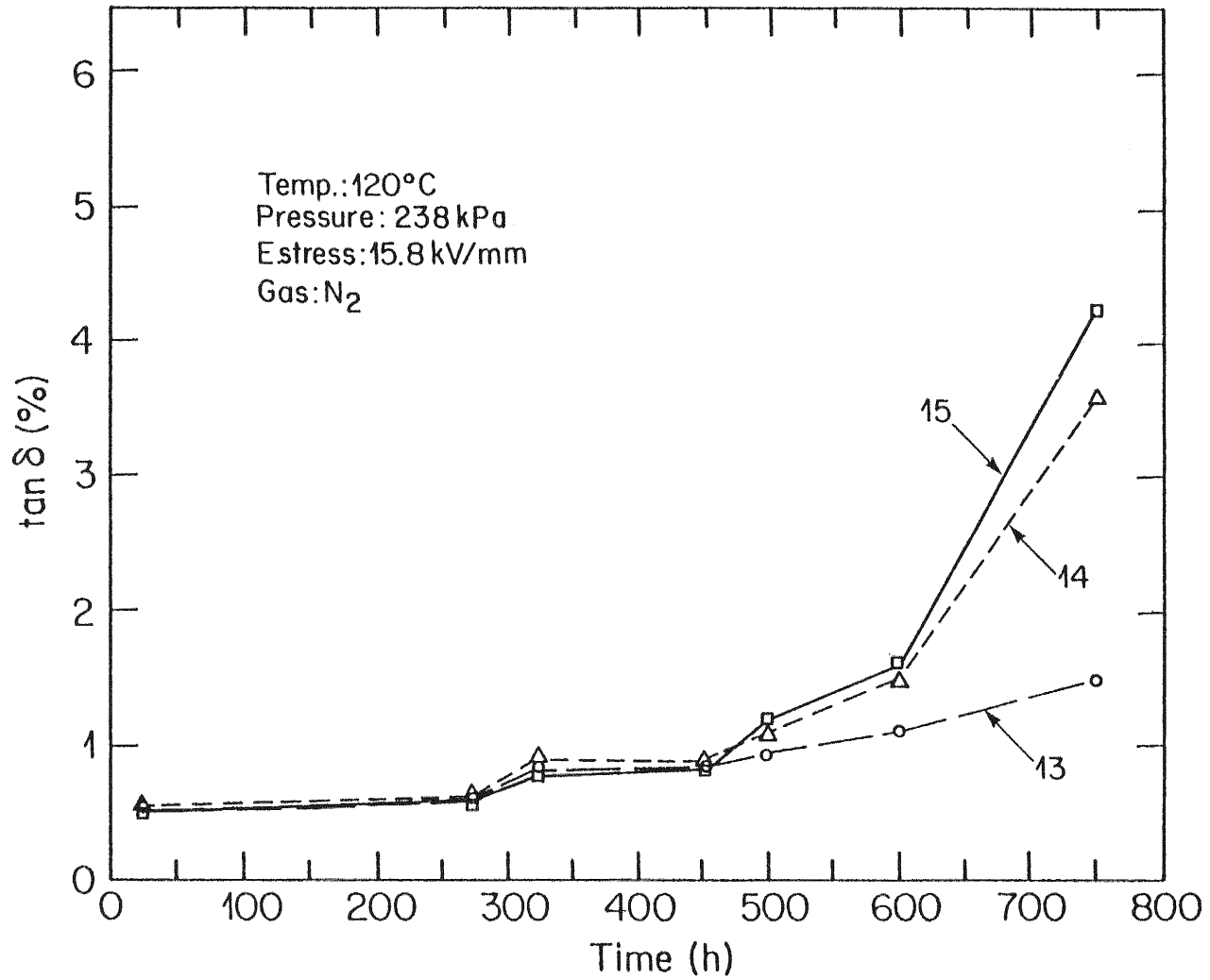


Figure 11: Tan  $\delta$  vs time of cable models pressurized with N<sub>2</sub> tracer gas

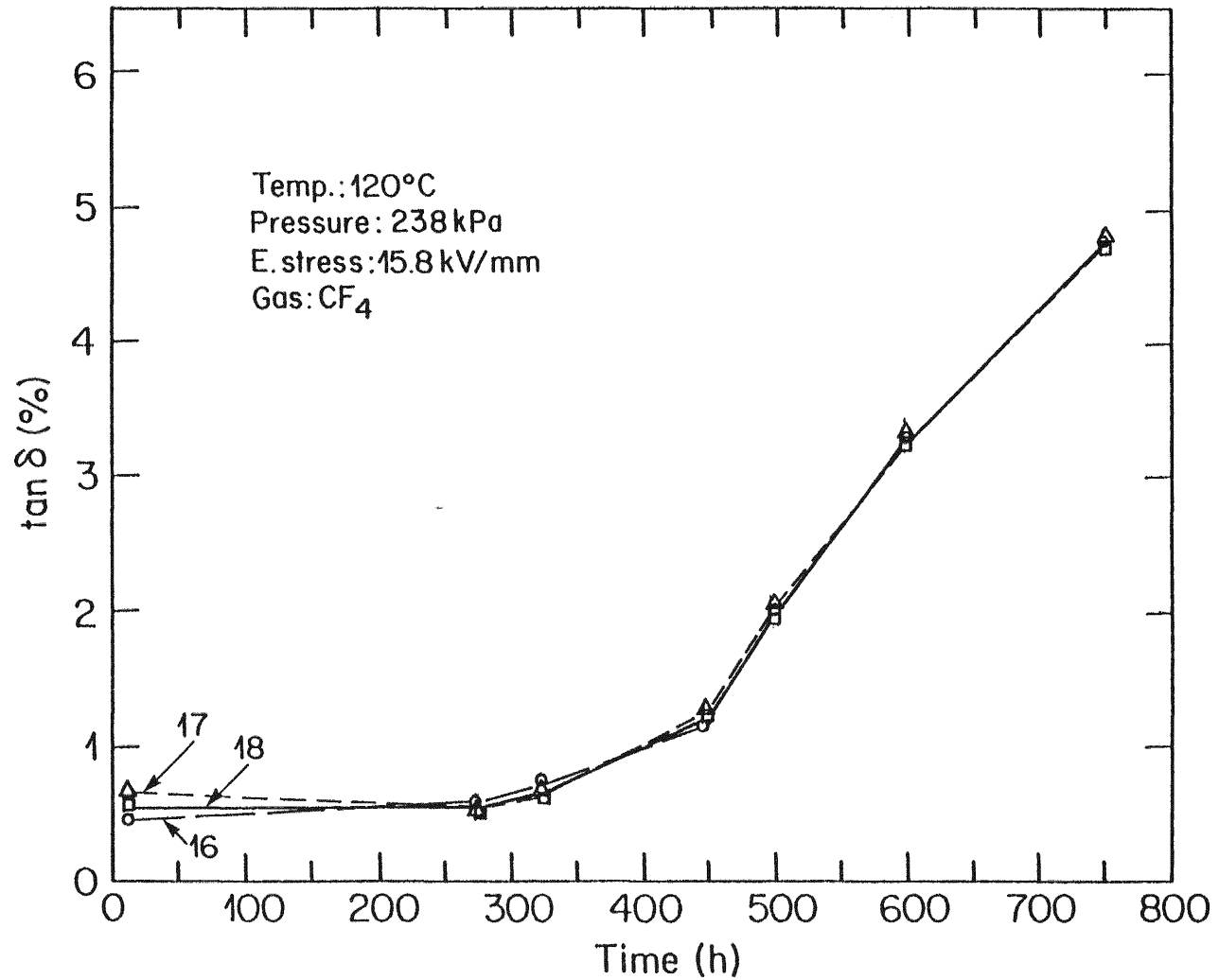


Figure 12: Tan  $\delta$  vs time of cable models pressurized with CF<sub>4</sub> tracer gas

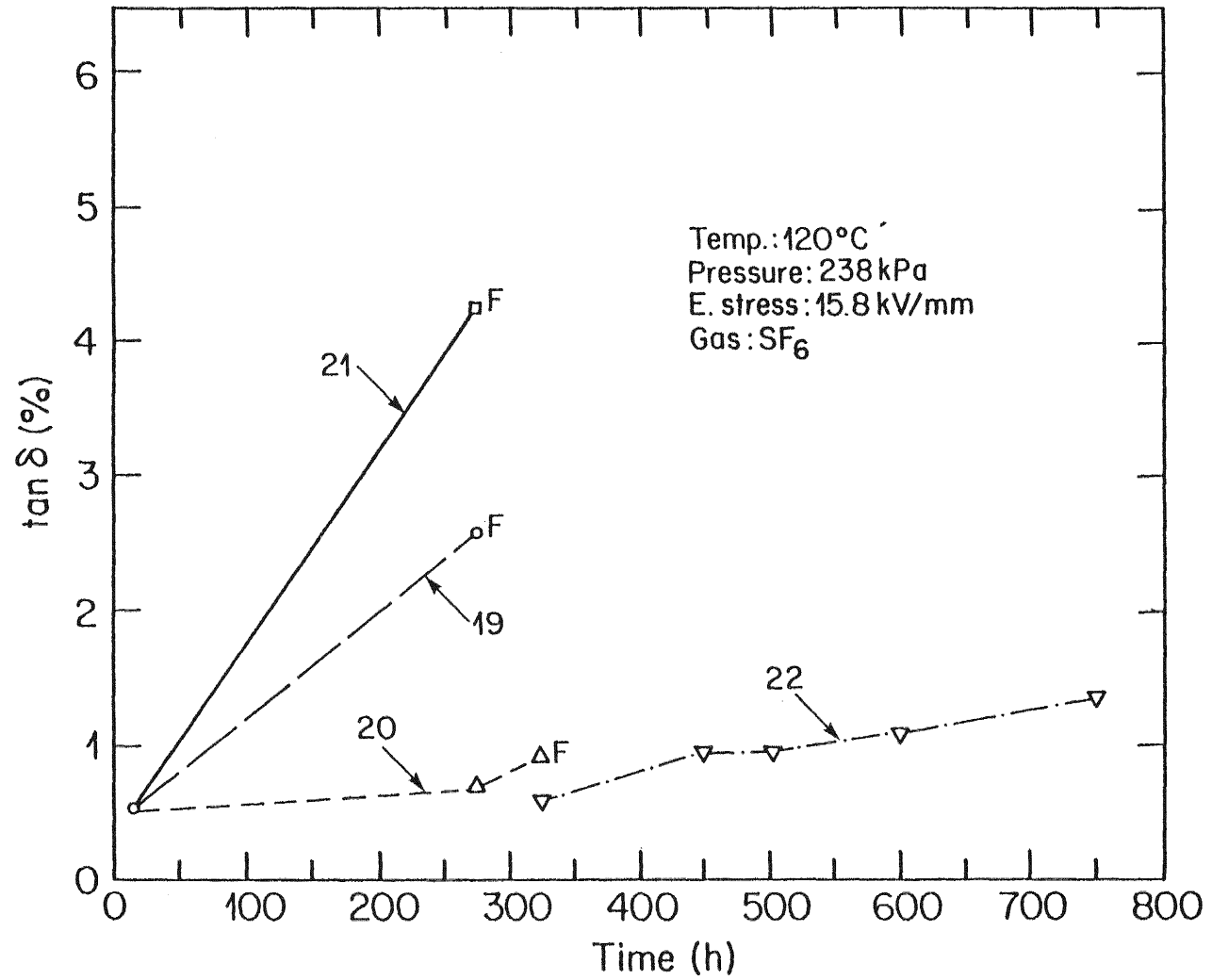


Figure 13: Tan  $\delta$  vs time of cable models pressurized with SF<sub>6</sub> tracer gas

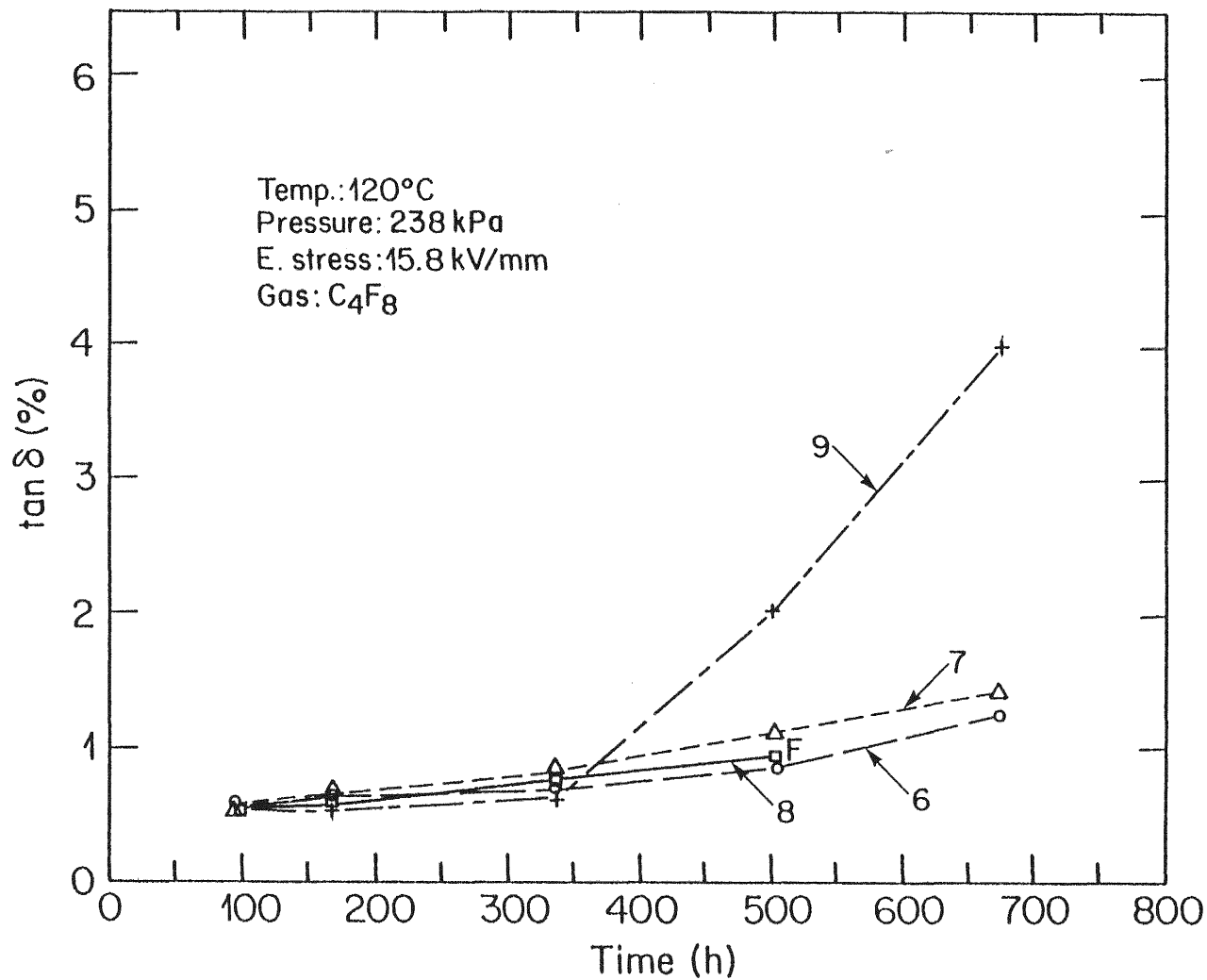


Figure 14: Tan  $\delta$  vs time of cable models pressurized with *c*-C<sub>4</sub>F<sub>8</sub> tracer gas

5.  $c\text{-C}_4\text{F}_8$  (Figure 14): A change of slope in the  $\tan \delta$  vs time curves of models 23 and 24 is again visible near 300 h. At 600 h, however, the losses of model 24 stopped following the same pace as those of model 23 to switch back to a lower rate of increase until the test was ended. Model No. 23 eventually failed at approximately 675 hours. The slope changed also for the sample No. 25 near 300 h, but  $\tan \delta$  went back shortly after to its original rate of increase.

### 3.3 AC breakdown tests

All the remaining cable models at the end of the aging test were tested for a.c. breakdown at  $85^\circ\text{C}$  and under a nitrogen pressure of 238 kPa. Voltage was raised following a ramp of approximately 500 V/sec until breakdown. The samples were kept in the same glass cells for the breakdown tests.

1. Breakdown of aged samples from aging test 1: The cells had to be depressurized for their transfer to a different test set-up and all samples showed low partial discharge inception voltage when repressurized for about two hours before the breakdown tests. Results of these tests are summarized in Table 3. Nitrogen and  $\text{CF}_4$  models showed a similar average breakdown stress of 43 and 42.8 kV/mm respectively while the  $c\text{-C}_4\text{F}_8$  samples failed at the somewhat higher average value of 46.6 kV/mm. The maximum deviation from average was 7.2% for  $\text{N}_2$ , 7% for  $\text{CF}_4$  and 1.7% for  $c\text{-C}_4\text{F}_8$ .

2. Breakdown of aged samples from aging test 2: The nitrogen samples were kept under a pressure of 150 kPa for several days until being

TABLE 3

AC BREAKDOWN OF AGED CABLE MODELS (Aging test 1)\*

Gas	Model No.	Breakdown voltage (kV)	Breakdown stress (kV/mm)	Average breakdown stress kV/mm
N <sub>2</sub>	1	25.5	46.1	43.0
	2	22.0	39.8	
CF <sub>4</sub>	3	25.0	45.2	42.8
	4	22.0	39.8	
	5	24.0	43.4	
c-C <sub>4</sub> F <sub>8</sub>	6	25.5	46.2	46.6
	7	26.2	47.4	
	9	25.5	46.2	

\* Voltage rise: 500 V/sec  
 Temperature : 85°C  
 Pressure : 238 kPa

repressurized to 238 kPa about two hours before the test.  $\text{CF}_4$ ,  $\text{SF}_6$  and  $\text{c-C}_4\text{F}_8$  samples were continuously kept under their full tracer gas pressure and were connected to a nitrogen gas line shortly before their breakdown. The He model No. 12 was left at atmospheric pressure in its sealed cell after removal from the oven and was repressurized with  $\text{N}_2$  to 238 kPa for the test. Results of the breakdown tests are summarized in Table 4.

Although the helium sample No. 12 showed intense corona activity when it was deenergized during the aging test, no significant partial discharge phenomenon was observed when it was tested for corona shortly before its breakdown. The sample eventually failed at the rather high electrical stress of 47.2 kV/mm. The three nitrogen models failed at 44.1 kV/mm, value 2.5% higher than the average B.D. stress of samples 1 and 2. The average B.D. stress of  $\text{CF}_4$  models is, with a value of 41.6 kV/mm, 2.8% lower than the corresponding data of samples 3,4 and 5. Sample No. 22, pressurized with  $\text{SF}_6$ , failed at 42.3 kV/mm and  $\text{c-C}_4\text{F}_8$  models failed at an average value of 46.4 kV/mm, only 0.4% lower than the  $\text{c-C}_4\text{F}_8$  models of aging test 1.

3. AC breakdown of unaged cable models: Four unaged samples, pressurized with nitrogen, were tested for breakdown. Two of these samples had the cell filling oil contaminated as specified in section 2.3. The breakdown data, tabulated in Table 5, show there is hardly any difference in breakdown stress value between the "clean" and contaminated samples.

#### 3.4 Dissection of cable models

All the models that had failed during aging and those submitted to

TABLE 4

AC BREAKDOWN OF AGED CABLE MODELS (Aging test 2)\*

Gas	Model No.	Breakdown voltage (kV)	Breakdown stress (kV/mm)	Average breakdown stress (kV/mm)
He**	12	26.1	47.2	47.2
N <sub>2</sub>	13	24.4	44.1	44.1
	14	24.4	44.1	
	15	24.4	44.1	
CF <sub>4</sub>	16	23.4	42.3	41.6
	17	23.4	42.3	
	18	22.2	40.2	
SF <sub>6</sub>	22	23.4	42.3	42.3
c-C <sub>4</sub> F <sub>8</sub>	24	26.8	48.5	46.4
	25	24.5	44.3	

\* Voltage rise: 500 V/sec  
 Temperature : 85°C  
 Pressure : 238 kPa

\*\* Aging stopped at 275 hrs because of too high level of partial discharges.

TABLE 5

## AC BREAKDOWN OF UNAGED CABLE MODELS\*

Gas	Model No.	Oil contaminated	Breakdown voltage (kV)	Breakdown stress (kV/mm)	Average Breakdown stress (kV/mm)
N <sub>2</sub>	26	no	27.0	48.8	48.8
	27	no	27.0	48.8	
N <sub>2</sub>	28	yes	26.2	47.4	48.0
	29	yes	26.8	48.5	

\* Voltage rise: 500 V/sec  
Temperature : 85°C  
Pressure : 238 kPa

breakdown tests were dissected and the following observations, (summarized in Table 6), were made:

1. Only two samples over a total of 29 had failed at the edge of the low voltage electrode (in the butt-gap separating the electrode from the stress cone).
2. All breakdowns except five occurred radially through two paper layers and two butt-gaps. This is a normal breakdown scheme for a thin insulation wall built with a 35/65 registration. The five "abnormal" breakdowns, occurred through insulation walls having a slight misalignment of the registration.
3. The models, except the helium samples, that failed during aging showed black spots with the paper brittle in the damaged zone indicating a strong partial discharge activity for an extended period of time. The SF<sub>6</sub> samples had their tin low voltage electrode extensively oxidized as shown in Figure 15. Dark straight oblique lines seen on the tin foil correspond to the butt-gaps of the first outer insulation layer. The tin electrodes of c-C<sub>4</sub>F<sub>8</sub> models were stained in a similar fashion with whitish deposits. The helium samples had their tin foil electrode slightly opened at several places along the outer edge. Bubbles were seen coming out from these openings during the aging.
4. Some of the samples that did not fail during the aging test had traces of partial discharge activity visible on the insulation.

TABLE 6

## DISSECTION OF CABLE MODELS

Model No.	Gas	Failed in aging	Breakdown in		Registration		P.D. traces
			cone	insulation	O.K.	Off	
1	N <sub>2</sub>			x	x		x
2	"			x	x		x
3	CF <sub>4</sub>			x		x	?
4	"			x	x		x
5	"			x	x		
6	c-C <sub>4</sub> F <sub>8</sub>			x	x		
7	"		x		x		
8	"	x		x	x		x
9	"			x	x		x
10	He	x		x	x		
11	"	x		x	x		x
12	"	x		x		x	
13	N <sub>2</sub>			x	x		
14	"			x	x		x
15	"			x		x	x
16	CF <sub>4</sub>			x	x		
17	"			x	x		
18	"			x	x		
19	SF <sub>6</sub>	x		x	x		x
20	"	x		x		x	x
21	"	x		x	x		x
22	"			x	x		
23	c-C <sub>4</sub> F <sub>8</sub>	x		x		x	x
24	"			x	x		x
25	"			x	x		x
26	N <sub>2</sub>			x	x		
27	"		x		x		
28	"			x	x		
29	"			x	x		

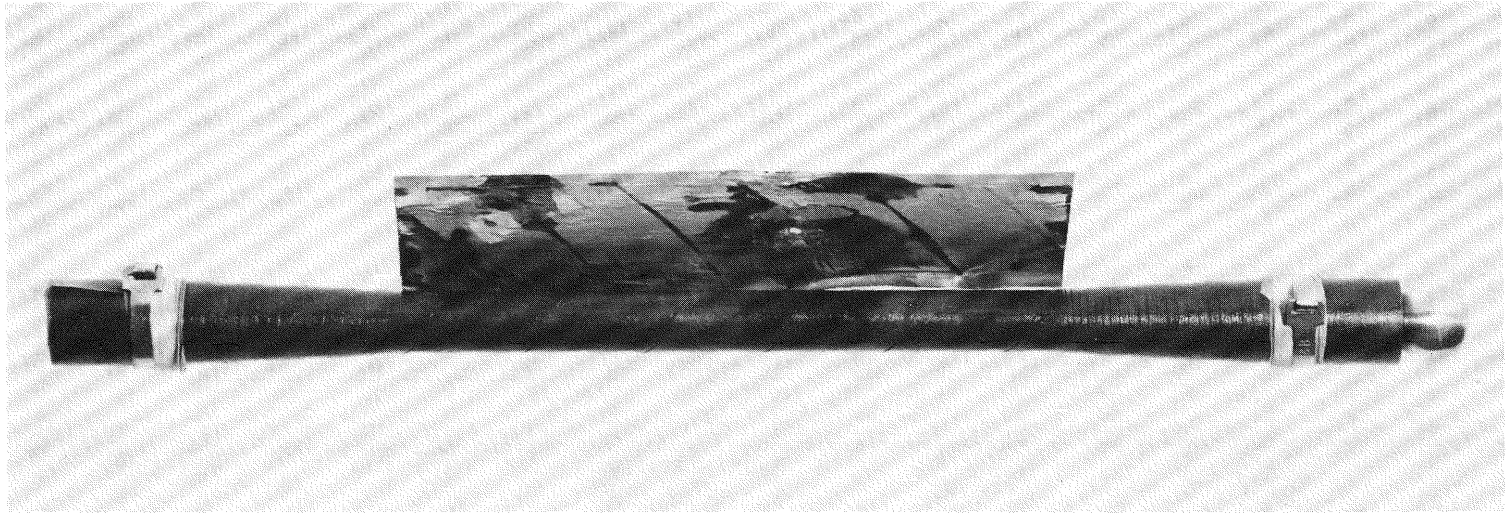


Figure 15:  $SF_6$  pressurized cable model during dissection  
after breakdown

#### 4.0 DISCUSSION

The aging tests Nos. 1 and 2 were performed on cable models having a rather high initial level of dielectric losses due to contamination of the virgin oils used as impregnants with the result that some instability of the power factor could be expected. All models but five i.e. Nos. 10, 11, 12 (He) and Nos 19, 21 (SF<sub>6</sub>) experienced about the same rate of increase of  $\tan \delta$  for the first 300 hours. The steady rise of the losses may be related to the presence in the oil of an increasing number of ions some of which were already in the insulation, others coming from various physical and chemical processes. It is interesting to note that a new phenomenon appeared around 300 hours by raising the  $\tan \delta$  rate of increase of most of the models. No satisfactory explanation has yet been found. The examination of the test schedules did not reveal any incident that could have triggered the effect. The possibility of having had a similar hidden problem twice with the testing apparatus is very remote since the two aging tests were done within two distinct time windows. Furthermore as one can see by comparing Figure 7 through 14 with Table 6, the models that showed the sharpest increase of their losses has traces of partial discharge activity on the paper. It would be difficult however to consider solely this partial discharge activity to explain the phenomenon discussed above since other models which also had a faster increase of  $\tan \delta$  after 300 h did not show any traces of corona when dissected.

Since the samples pressurized with helium were removed after less than 300 hours of aging, the corona activity, although very intense, was

not strong enough to damage the papers and burned spots on the papers were, when visible, very small indeed. Model No. 12 behavior as described in section 3.3 obviously shows that the insulation had not been yet permanently damaged when its aging was aborted. Probably most of the helium gas had escaped from the oil during the rest period of the sample and all the gas bubbles in which the discharges were probably occurring had disappeared when it was tested successfully for corona activity.

The a.c. breakdown tests showed a slight advantage of  $c\text{-C}_4\text{F}_8$  models despite the fact that most of these models had spots of carbonized paper. Unaged nitrogen pressurized models had, as one could have expected, breakdown stress values higher (by  $\sim 9\%$ ) than those of the corresponding  $\text{N}_2$  aged models. The dispersion range of the breakdown values of all the 22 models, including the unaged samples, is rather small with a standard deviation of about 6%. This fact points out the difficulty that one may have in trying to select the best candidate tracer gas from the breakdown test data. All gases behaved relatively equally well.

One may select for comparison some of the best models by excluding data of samples that showed sharp increase of their  $\tan \delta$  and did have sustained partial discharges. For example, models No.5 ( $\text{CF}_4$ ), 6( $c\text{-C}_4\text{F}_8$ ), 13( $\text{N}_2$ ) and 22 ( $\text{SF}_6$ ) may be considered as good samples. The behavior with time of these models is very similar, except for the  $\text{CF}_4$  model.

## 5.0 CONCLUSION

The compatibility tests performed on the five gases selected as potential candidates to be used as tracer gases for oil leak detection in pipe cables lead one to conclude that:

1. Since the oil used for impregnation of the cable models had a high initial power factor, the instability of the power factor of several models may have been caused by the presence of the original oil contaminants rather than by the interaction of the tracer gases with the insulation.
2. Helium gave the poorest results with very strong corona activity in the three models at an early stage in the aging.
3. The voltage breakdown gradients were similar for all the gases with a slight lead however for the  $c\text{-C}_4\text{F}_8$ .
4.  $\tan \delta$  with time data of models that did not exhibit a dielectric losses runaway show that  $\text{N}_2$ ,  $\text{SF}_6$  and  $c\text{-C}_4\text{F}_8$  gave very similar results.
5. Further analysis of the oil samples collected after the aging and the breakdown test should give additional useful data for the interpretation of the results obtained.

During the aging, the oil in each test cell had increasing concentrations of the tracer gas until, depending in the kinetics of the gas/oil mixture, full saturation was achieved. The gas absorbing capacity of the oil may have been hampered by the presence of the tracer gas with, as a consequence, a smaller ability of the oil to absorb gases such as those resulting from the thermal degradation of the paper. Lower concentrations of tracer gases might have possibly given less corona problems.

It should be also said, at this point of the discussion, that an analysis of the gases dissolved in the oil (actually kept in sealed containers) might help in the selection of a tracer gas by identifying the decomposition by-products of the gases, some of which might be potentially harmful to the insulation and also to the personnel.

## APPENDIX C

### LEAK LOCATION MANUAL FOR HIGH PRESSURE OIL FILLED CABLE SYSTEMS

#### 1.0 INTRODUCTION

This manual describes the procedures that should be followed to locate an oil leak on a high pressure oil-filled cable system. The suggested leak location methods are ones that were developed by Power Technologies, Inc. under contract with the Electric Power Research Institute. Special thanks are due to the Consolidated Edison Company of New York for sharing their experiences and procedures for locating leaks; that background has been incorporated into this Manual.

#### 2.0 VERIFICATION OF A LEAK AND INITIAL STEPS

##### 2.1 Verification of a Leak

A large oil leak, such as one caused by a dig-in, is evidenced by inability of the pressurizing plant pump to maintain pressure. The existence of the leak is obvious and usually the location is also obvious.

Most leaks begin with a corrosion pinhole, however, and it is not uncommon to have a very small leak persist for months before its existence is verified.

Frequent checking of pumping plant reservoir tank oil level is the most common means of determining that a leak may exist, but care must be taken to account for the effects of cable oil expansion/contraction due to load cycling and to changes in ambient earth temperature.

For circuits on which the pressurizing pump operates only upon demand for oil by the feeder (in contrast to feeders on which the pump runs continuously for slow circulation of oil), frequency of operation can be an indication of the leak.

Verification of the existence of a leak can be as simple as monitoring the pressurizing plant storage tank oil level until it falls to a point beyond which there is no doubt of the cause.

If there is a pair of feeders sharing the same storage tank, the one with the leak can be determined by valving off both ends of each feeder and watching the rate of decay of pressure. Since the two feeders will probably be carrying the same load, thermal expansion/contraction effects should be balanced. Extreme care must be taken to insure that all pressure gauges work correctly and that they do indeed monitor pressure in the cable pipe, and personnel man the pumping plant to reconnect the pumps should pressure begin to fall to a dangerous level on an energized feeder. Care should be taken to maintain the minimum operating pressure or greater at every point on the line, taking into account any elevation differences in the route of the feeder. If system conditions permit, the two feeders can be deenergized and allowed to cool before the comparative pressure drop test is made. Greater accuracy will result because of the more stable thermal conditions, and there will be no concern of feeder damage due to inadvertent loss of pressure.

For a single feeder, the pumping plant level must be monitored, or the feeder may be valved off and pressure drop charted for constant thermal conditions.

## 2.2 Initial Steps

If the leak rate is sufficiently low that pressure can easily be maintained, and if there are no other restrictions, then the feeder may be kept energized at nor-

mal pressure until it must be deenergized and pressure reduced if required for leak location efforts.

If the leak is large enough to jeopardize feeder safety, the feeder must be deenergized, and pressure on the line should be reduced to the minimum allowable level to maintain a pressure of about 310 kPa (45 lb/in<sup>2</sup>) in the potheads or in the high point of the cable if it is substantially higher than either set of potheads.

For moderate leaks, if oil loss is of concern the feeder can be deenergized and pressure reduced as described above to minimize oil loss.

Although individual utility practices may vary, it is recommended that potheads be vented before reenergization of the feeder after any length of time at reduced pressure.

The first step in leak location is to walk the route of the feeder; there have been many occasions when oil surfaced in the street before there was a chance to employ sophisticated leak location procedures.

Pressurizing plants, potheads, and connecting piping should also be checked for oil leaks.

Lifting of covers on the feeder manholes and other nearby utility manholes---distribution cable, telephone, sewer--- should be the next step.

### 3.0 RAPID DETERMINATION OF GENERAL AREA OF A LEAK

For feeders more than two kilometers (1.2 miles) or so, the methods suggested for pinpointing a leak (See Section 4) would be too time consuming, so a faster method must be used to isolate the leak to one or two manhole sections.

### 3.1 Sectionalize by Freezing

The feeder can be halved, quartered, etc. by establishing freezes of the oil in the pipe by use of jackets around the pipe through which liquid nitrogen is passed. Pressure drop is then monitored in the isolated section. Excavations are usually required although there are occasions where there is sufficient pipe length in a manhole to install the freezing equipment.

Once the leak is isolated to a sufficiently short section, boreholes or test pits can be used to pinpoint the leak, or the methods of Section 4 can be employed.

### 3.2 Sectionalizing Valves

Some utilities employ stop joints in the cable, with bypass piping around the stop feature of the joint. If the stop feature is relatively leak-tight and if the bypass valves do not seep oil, the leak can be isolated to the section of pipe between two stop joints.

This procedure requires deenergizing the feeder, although if totalizing flowmeters are available as used by Con Edison, it is possible to monitor oil flow into each section while the feeder is energized. (The totalizing flowmeter employs an extremely accurate flowmeter with electronic circuits to integrate the total flow during the period of interest, and indicate whether there is a net loss of oil in one section versus another section.)

### 3.3 Flow Direction Indicators

An Enhanced Conductivity Oil (ECO) probe was developed for insertion into a joint casing to determine the direction of oil flow. The following paragraphs give the steps required for use of the probe: (Refer to Figure 1)

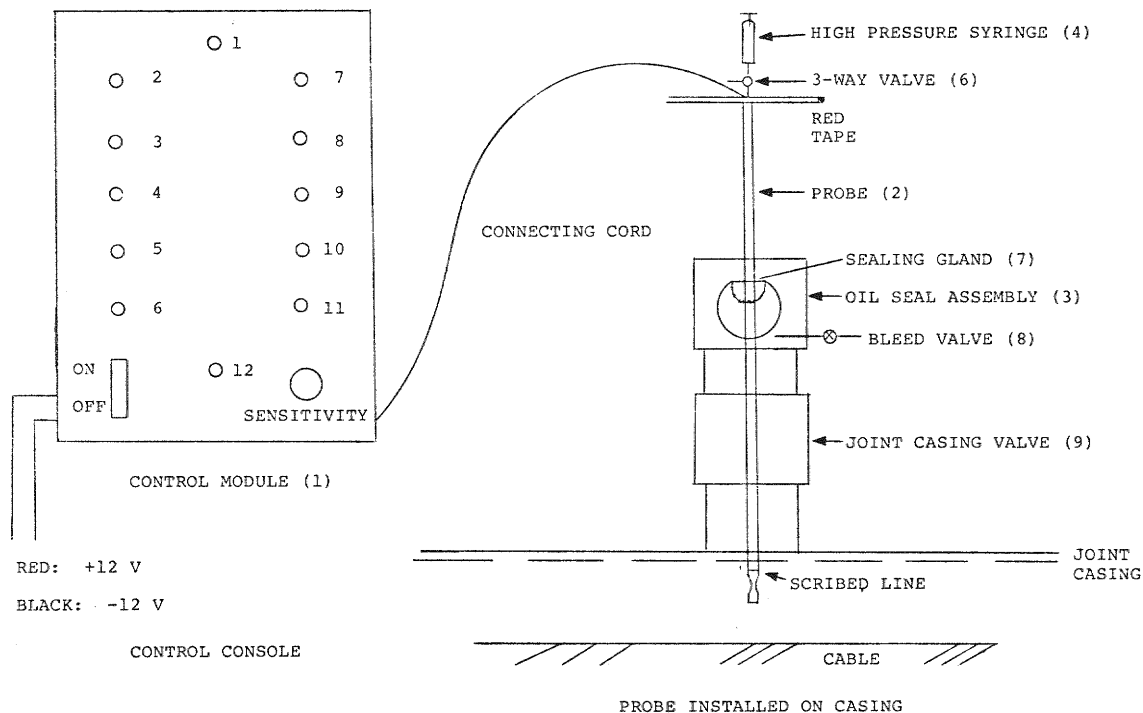


Figure C-1. Enhanced Conductivity Oil Probe.

Equipment Preparation The Enhanced Conductivity Oil to be used must be compatible with the oil in the cable circuit. The appropriate oil can be obtained from Welch Chemical Company, Schenectady, N.Y., Attention Mr. Marshall Welch, (518) 346-8878. The oil in the feeder should be specified (Sun #6, Sun #4, low viscosity polybutene, regular viscosity polybutene). The oil can be shipped anywhere in the U.S within a day. It can be stored for three months.

The Enhanced Conductivity Oil probe and control module should be unpacked and inspected. A new twelve volt lantern battery, or a 12 volt automobile battery should be connected to the power leads of the unit, with care taken to maintain the correct polarity. (If an automobile battery is to be used, it should be disconnected from the vehicle.) The probe should be connected to the control module, the module turned "On" and the sensitivity turned to

the point where the LED's just start to glow. Operation of the circuitry can be checked by gently pressing a finger against a pair of contacts in the probe and observing that the appropriate LED's light.

1. Deenergize the feeder and leave it deenergized for at least 36 hours to allow thermal equilibrium.
2. At a joint near the center of the feeder, remove any protective covering on the joint casing vent valve and install the oil sealing assembly (Item 3 of Figure 1).
3. Loosen the sealing gland in the housing and carefully slide the probe (Item 2) into the sealing assembly to the line scribed on the probe. This will give a double O-ring seal on the probe.
4. Adjust the position of the probe until it is vertical and gently tighten the sealing gland. Tighten the retaining bolts (Item 5) to prevent the probe from being pushed from the sealing assembly by oil pressure.
5. Carefully measure the distance from the scribed line on the sealing assembly to the top of the casing. Add to that distance the thickness of the casing and one-half the distance from the casing to the top cable in the joint (obtained from manufacturer's joint drawings).
6. Make sure that the three-way valve on the probe (Item 6) is closed, and open the joint casing valve slowly---observe any leakage of the assembly and repair the leakage if required.
7. Push the probe into the casing the distance determined in the preceding step. Orient the handle of the probe with the axis of the casing and note the direction of the red end of the handle. Tighten the sealing gland.
8. Connect the female connector on the probe to the male connector on the control box. Turn on the unit and adjust the sensitivity control until the LED's just light, then decrease the sensitivity slightly.
9. Fill the high pressure syringe (Item 4) with the correct enhanced conductivity oil to the 1 cc level. Invert the syringe and depress the plunger until all air is expelled. Connect the syringe to the three-way valve, Item 6. Open the three-way valve to atmosphere until oil flows out of the valve, to insure removal of any air in the injection line. Connect the syringe.
10. Open the three-way valve and slowly inject the enhanced conductivity oil. (It should take about 30 seconds to inject the 1 cc.) Close the three-way valve and remove the syringe.

11. Observe the lighting of the LED's on the panel of the control module. They are arranged in the order of the pins on the probe, with the red end of the probe handle on the right hand side of the control module.

Lighting of #11 or #12 indicates no flow, or a flow of a magnitude too low for the sensitivity of the probe. Lighting of any opposite pair of lights (e.g. #2 & #7) indicates difficulty with the unit or a very low flow.

Lighting of #9 and #10 indicates a low flow to the right, lighting of #1 and #2 indicates a high flow to the left, etc.

12. After a reading is achieved, open the bleed valve (Item 7) and drain 18 liters (5 gallons) of oil. This will remove any trace of the enhanced conductivity oil.
13. Wait five minutes or more, loosen the packing gland 1/4 turn, rotate the probe 180 degrees, tighten the packing gland and repeat steps 9-12. Lighting of the corresponding set of lights on the opposite side of the display will verify the first reading.
14. Loosen the packing gland one-quarter turn and raise the probe to the scribed line (see Step 6) and no farther.
15. Close the valve on the joint casing.
16. Remove the probe assembly and replace the protective cap on the joint casing valve. Repair any corrosion coating that was damaged during the operation.
17. Repeat the above steps, halving the feeder each time, until the leak is isolated to adjacent manholes.

For non-cable pipes (e.g. oil return lines) greater resolution can be obtained by pressure-tapping the pipe and inserting the probe at succeedingly closer locations. This procedure is not recommended for cable pipes until there are improvements in the present state of the art of pressure-tapping. Note that a gate valve, or a full-port ball valve is required, to give adequate free area for insertion of the probe. The probe is designed for the common 5.08 cm (2") vent valve and adaptors are included for connecting to a 2.54 cm (1") valve. It should be possible to pressure-tap the joint casing if no vent valve exists, since the position of the cables should be well-known and since there is little chance that they will contact any burrs that may be left due to the tapping.

Use of the probe should allow isolating the leak to a manhole section, and the techniques described below should be employed to pinpoint the leak.

#### 4.0 PINPOINTING THE LEAK

Two methods were developed for pinpointing the leak by carefully surveying the ground along the feeder route.

Leak Location Dogs were proven quite effective, and are capable of identifying cable oil alone so that no additives need to be employed.

Tracer Gases can also be used on occasions where the dogs may not be effective.

#### 4.1 Leak Location Dogs

Two organizations that currently (late 1981) have leak location dogs trained and proven under the EPRI/PTI contract are:

Guardian Training Academy

Windsor, Ontario

Mr. Glen R. Johnson

(519) 737-6372

Southwest Research Institute

San Antonio, Texas

Dr. Edward E. Dean

(512) 684-5111 Ext. 2683

The best method of deploying the dogs will be determined by wind, traffic, nature of the leak, type of terrain, etc; the two organizations listed above are well qualified to conduct a search for cable oil and it is suggested that the utility efforts be guided by the handler's requests.

The following items should be kept in mind when preparing for trials with the leak location dogs.

1. The dogs can efficiently search a distance of only about two kilometers (1.2 miles). The leak should be isolated to a section of pipe that length or less before the dogs are employed.
2. A sample of oil from the leaky feeder should be provided to the handlers. There is a subtle variation of odor among oils and the dogs can be keyed to the correct oil.
3. The dogs are generally unaffected by traffic and other urban distractions. There is often an advantage, however, to having them work late at night or early in the morning. The utility should be prepared to have crews available during second and third shifts.
4. Adequate traffic protection is mandatory for protection of the dogs, handlers, and utility work crews.
5. The feeder route should be marked, or at least should be well-known by the utility before the dogs begin work.
6. In one leak location effort, the dogs were unsuccessful because the oil was jetting directly into a sewer, this This underlines the importance of checking sewer manholes.

#### 4.2 Tracer Gases

Sulfur Hexafluoride (SF<sub>6</sub>) can be added as a tracer gas to cable oil, and sought from above-ground with a portable detector.

If the SF<sub>6</sub> has been blanketing the pressurizing plant storage tank for any length of time, the gas should leave the pipe as soon as the leak begins, and leak location can proceed as outlined below.

If the gas is to be added at the beginning of leak location operations, the steps given below should be followed: (See Figure 2)

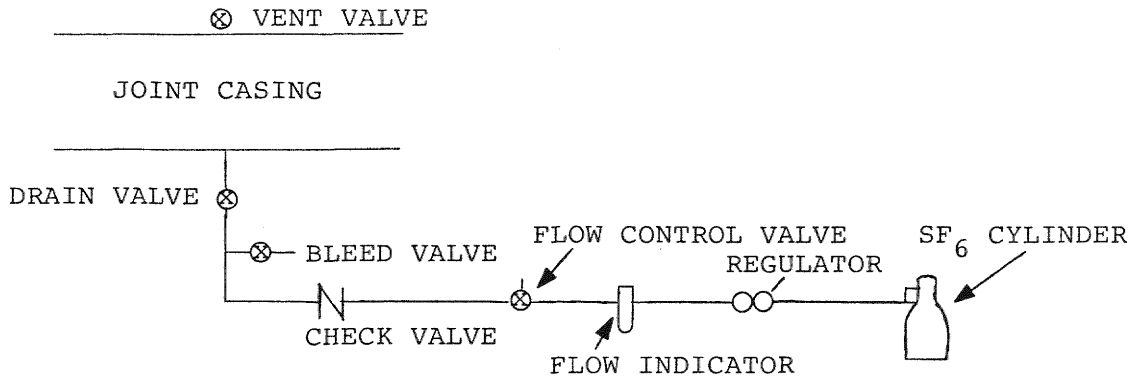


Figure C-2. Injection of SF<sub>6</sub> into Feeder.

1. Determine the general location of the leak by freezes or a flow direction indicator as outlined in Section 3.
2. At a manhole on either side of the leak, connect a cylinder of SF<sub>6</sub> to the joint casing as shown in Figure 2. Leave all valves closed.
3. Establish an oil flow from than manhole toward the leak, for example by use of a pressurizing pump with the oil circulating to a companion feeder. Alternatively, the oil can be collected in a pressurizing plant oil reservoir tank, or in a tank truck. In the latter two cases, calculate the volume of oil in that section of cable, add 25%, and make sure that there is sufficient storage capacity available. Oil volumes per unit length of pipe for many common cable and pipe sizes are given in Table 1.

TABLE 1  
OIL VOLUME FOR COMMON PIPE AND CABLE SIZES

	Oil Volume Gallons/Foot	Oil Volume Liters/Meter
10-3/4" Pipe		
4.25" cable	2.1	26
4.0"	2.4	30
3.75"	2.6	32
3.5"	2.8	38
3.25"	3.1	
8-5/8" Pipe		
3.5" cable	1.2	15
3.25"	1.4	17
3.0"	1.6	20
2.75"	1.8	22
2.5"	2.0	25

4. Open the valve on the SF<sub>6</sub> cylinder, purge SF<sub>6</sub> through the purge valve, close the purge valve and with the regulator set at a pressure 69 kPa (10 lb/in<sup>2</sup>) above the line pressure at that point (maximum pressure 2070 kPa (300 lb/in<sup>2</sup>), adjust the flow control to a level corresponding to the oil flow rate.
5. Continue adding SF<sub>6</sub> to the feeder until the gas appears in the joint the other side of the leak. The approximate length of time can be calculated by dividing the oil volume in the section of cable by the flow rate of the pump circulating oil through the feeder.
6. Shut off the valve on the SF<sub>6</sub> tank and shut off the valve on the joint casing.
7. Wait a period of at least six hours before beginning leak location. Prior to the end of that period, place boreholes in the pavement at a spacing not to exceed 5 meters (15 feet). The boreholes may be small---2 cm diameter by 12.7 cm deep (3/4" by 6").

As an alternative, standard traffic cones may be placed over the feeder route at a spacing not to exceed 3 meters (10 feet). There should be no air space between the cone and the street surface. The cone should be placed over a crack in the pavement if possible.

8. After the six hours, begin leak location using the Ion Track Instruments Model 56 Leakgun or equivalent instrument with a sensitivity of better than 0.1 part per million SF<sub>6</sub> in air. (As of mid-1981, the Model 56 Leakgun was the only instrument that had been tested and found suitable for utility use in leak location). Refer to the operating manual for the instrument for detailed instructions on its use and calibration. Highlights of its use are as follows: (Refer to Figure 3 for identification of the components).

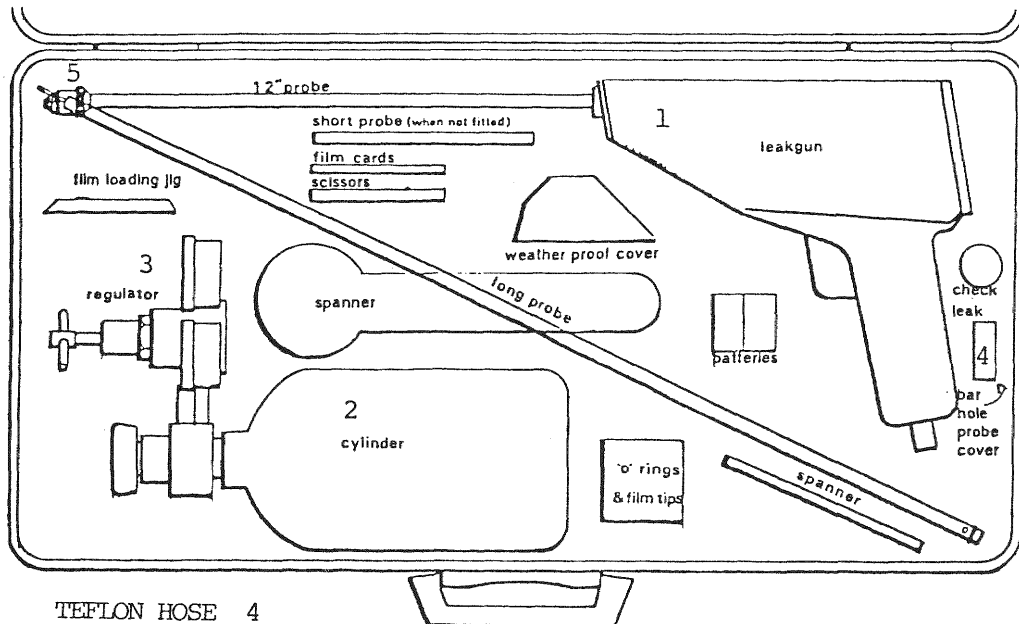


Figure C-3. Model 56 Leakgun as Packed in Carrying Case.

- a. Start with fresh batteries (two 9-volt 1604 transistor batteries) and a fresh tank of Argon gas pressurized at 6900 to 9600 kPa (1000-1400 lb/in<sup>2</sup>).
- b. Connect one end of the teflon hose to the regulator using the fitting provided in the kit. Open the valve on the Argon tank and adjust the regular to give a small flow. Purge the teflon hose for at least two minutes, then shut off the Argon supply by backing out the T handle on the regulator. Proceed quickly to the next step.
- c. Connect the other end of the teflon hose to the fitting at the base of the Leakgun. Adjust the Argon pressure to 69 kPa (10 lb/in<sup>2</sup>) and tighten the locknut on the regulator handle to prevent inadvertent changes in pressure.
- d. If the Leakgun has not been used for more than a day, purge with Argon for at least an hour before attempting to use the Leakgun.

- e. Turn the Selector Switch to "Battery Check", squeeze the trigger on the Leakgun, and make sure that the meter reading is 60 or greater. Replace the batteries if the reading is less than 60.
- f. Turn the Sensitivity Switch to any other position, squeeze the trigger, simultaneously press the "Check Detector" button, and see that the meter reading is 40 or greater. If the meter reads less than 40, continue purging with Argon, and take readings every fifteen minutes until 40 or greater is achieved.
- g. The film tip should be replaced periodically. This replacement should be done in the shop rather than the field; refer to the manufacturer's instruction booklet.

The batteries are only in the circuit when the trigger is squeezed so they should last for the duration of leak location efforts. Argon flows through the Leakgun continuously as long as the tank valve is open and the regulator is adjusted to a positive pressure. The small tank should last 16 hours, but it is recommended that it be replaced every shift. UNDER NO CONDITIONS SHOULD THE PRESSURE IN THE TANK BE ALLOWED TO DROP TO LESS THAN 1000 KPA (150 LB/IN<sup>2</sup>). Otherwise, the detector could become contaminated and require a long purging period, or it may even require return to the manufacturer for repairs.

9. Turn the Selector Switch to lowest sensitivity and verify operation of the unit by obtaining a reading on the Check Leak.
10. Adjust the Selector Switch to maximum sensitivity, zero the meter using the Zero Control knob, and place the probe in each of the cones or boreholes for a period of about five seconds.
11. When an indication of tracer is found, note the location and make additional boreholes (or place additional traffic cones) at a spacing of about 1 meter (3').
12. Wait one-half hour or more, then check each borehole or cone and determine the point of maximum tracer concentration.
13. After repair of the leak, the oil containing the tracer can be removed from the system if desired. An oil tank truck having a capacity equal to the amount of oil in the section plus 25% should be connected at a manhole at one end of the affected section, and oil should be pushed from the other end until sampling shows that no SF<sub>6</sub> is present. A small quantity of oil should then be flushed from the other direction to insure removal of all tracer.

The oil can be degassified and returned to the pressuring plant oil storage tank.

## 5.0 REPAIR OF THE LEAK

The means of repair of a leak will obviously vary due to the type and location of the leak.

For a corrosion pinhole in a section of line pipe, which is the most common type of leak, the correct size Adams clamp (available from large pipe supply houses) can be placed over the leak and the bolts tightened to stop the flow of oil.

A permanent repair is then made by placing a larger diameter split sleeve (Dresser Style 90, also available from major pipe supply houses) over the Adams clamp, and welding the split sleeve. It is recommended that a small oil flow be maintained in the cable pipe to help prevent overheating of the oil and cables. The welder should take care to avoid the use of unnecessary heat.

A second method of repair is to take a section of the same-size pipe, cut a coupon about 15 cm (6") wide and 30 cm (12") long, heat the coupon and open it until it fits closely over the outside of the affected pipe.

A small hole is then drilled in the center of the coupon and the hole is tapped. That hole is then placed directly over the leak and the edges of the coupon are welded. A plug is then fitted in the hole, and welded in place.

In both cases, after welding is complete a pressure test should be done by increasing line pressure above normal operating pressure (With care taken to avoid exceeding rated pressure of potheads or other components) and examining for leaks.

The corrosion coating should then be carefully repaired.

#### 6.0 RETURN OF THE LINE TO SERVICE

If there has been no need to reduce the pressure in the cable pipe, no special precautions need to be taken and the line can simply be reenergized. (The amount of leaked oil must of course be replaced in any case.)

If the line has been at reduced pressure for any length of time, the potheads should be vented to remove any gases that may have evolved during leak location and repair, or earlier. This step is not mandatory since the pressure should not have been low enough to allow gas evolution---but it is a worthwhile precaution. In the case of potheads enclosed in SF<sub>6</sub> bus, the difficulty in obtaining access for venting suggests that a utility be especially cautious in maintaining adequate oil pressure at the potheads.

The line should be left at full operating pressure for at least six hours before reenergization to make sure that any remaining gases are redissolved.



## APPENDIX D

### MAJOR SUBCONTRACTORS

Listed below are the major subcontractors to PTI for the leak location contract, along with the names of the individuals who were in charge of the subcontracts. Also listed are organizations and individuals that provided valuable input to the program by conducting demonstrations of leak location equipment and procedures at no cost to the EPRI/PTI program.

#### Earth Resistivity Changes

Southwest Research Institute  
8500 Culebra Road  
San Antonio, Texas 78228  
Mr. L. Fountain (512) 684-5111, Ext. 2776  
Earth Resistivity Studies

#### Flow Direction Indicators

Massachusetts Institute of Technology  
Room 3-137  
Cambridge, Mass. 02139  
Dr. L. R. Glicksman (617) 253-2233  
Consultation on Hydraulics and Thermodynamics

Welch Chemicals Company  
140 Edison Avenue  
Schenectady, N.Y. 12305  
Mr. M. Welch  
Development of Enhanced Conductivity Oil

#### Infra-Red Scan

General Electric Company  
Instrument Services Division  
Schenectady, N.Y. 12305  
----- (518) 385-2195  
Infrared Scanning Equipment

Leak Location Dogs

Guardian Training Academy  
R. R. 1, Oldcastle  
Ontario, NOR 1LO, Canada  
Mr. G. R. Johnson, (519) 737-6372  
Leak Location Dogs

Southwest Research Institute  
8500 Culebra Road  
San Antonio, Texas 78228  
Dr. E. Dean, (512) 684-5111 Ext. 2683  
Leak Location Dogs

Microphony

Heath Consultants  
100 Tosca Drive  
Stoughton, MA 02072  
Mr. D. Keller (617) 344-1400  
Leak Location by Acoustic Methods

Radioactive Tracers

Columbia University  
289 Engineering Terrace  
New York, N.Y. 10027  
Mr. P. Lorio (212) 280-4442  
Consultant for Radioactive Tracers, Microspheres

Rensselaer Polytechnic Institute  
Troy, N.Y. 12181  
Prof. D. Aulenbach (518) 270-6541  
Consultant for Radioactive Tracers

Subsurface Radar

Geophysical Survey Services, Inc.  
15 Flagstone Drive  
Hudson, New Hampshire 03051  
Mr. J. Rosetta (603) 889-4841  
Subsurface Radar Equipment and Consulting

Technos, Inc.  
P.O.Box 330891  
Miami, Florida 33133  
Mr. R. Benson (305) 634 4507  
Consultants in Earth Sciences

Tracer Gases

Institut de Recherche de l'Hydro Quebec (IREQ)  
Varenes, Quebec  
JOL 2FO, Canada  
Dr. D. Couderc (514) 652-8219  
Model Cable Compatibility Tests

Rensselaer Polytechnic Institute  
Troy, N. Y. 12181  
Prof. E. R. Altwicker (518) 270-6367  
Gas Diffusion/Attenuation, Instrumentation

Union College  
Schenectady, N.Y. 12308  
Prof. R. W. Schaefer (518) 370-6249  
Chemistry of Tracer Gases, Instrumentation



## APPENDIX E

### MATERIAL SUPPLIERS

Listed below are the organizations that supplied major material items for use in the leak location contract. There are several firms listed in the "Acknowledgments" section of the report that are not in the listing below. Those firms donated materials that are not the end product of the firm. The contributions of the organizations are gratefully acknowledged: General Electric Company, Mr. J. Atkins, tracer gases; Phelps Dodge Cable and Wire Co, Mr. E. Allam, Sun XX oil; Pirelli Cable Corporation, Mr. M. Buckweitz, paper for model cables; Underground Systems, Inc., Mr. P. Alex, Sun XX oil; Westinghouse/Waltz Mill Test Facility, Mr. J. Cooper, loan of donut-type high current transformers.

#### Flow Direction Indicators

Cosden Oil Company  
Big Spring, Texas  
Polybutene cable oil

Fischer Scientific  
(Local Offices Nationwide)  
Infusion Pump, High Pressure Syringes

Perma-Craft Plastics, Inc.  
Route 67  
Ballston Spa, N.Y. 12020  
Acrylic Joint Casing

Tat Engineering, Inc.  
300 Shaw Drive  
North Branford, Conn. 06741  
Dispensing Pump

Underground Systems, Inc.  
P.O.Box 27  
Armonk, N.Y. 10504  
345 kV Splice Materials

Welch Chemicals, Inc.  
140 Edison Avenue  
Schenectady, N.Y. 12305  
Enhanced Conductivity Oil

Tracer Gases

Allied Chemical Company  
(Local Representatives Nationwide)  
Sulfur Hexafluoride

Ion Track Instruments  
109 Terrace Hall Avenue  
Burlington, Mass. 01803  
Portable Electron Capture Detectors

Matheson Chemicals, Inc.  
(Local Representatives Nationwide)  
CF<sub>4</sub>, gas mixtures, gas-handling equipment

PCR Research Chemicals, Inc.  
P.O. Box 1778  
Gainesville, Fla. 32602  
c-C<sub>4</sub>F<sub>8</sub>

## APPENDIX F

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