Chapter 10

Maintenance of Liquid Insulation

December 1990

Power System Maintenance Manual

WESTERN
AREA POWER
ADMINISTRATION

MAINTENANCE OF LIQUID INSULATION

DECEMBER 1990

WESTERN AREA POWER ADMINISTRATION
POWER SYSTEM MAINTENANCE MANUAL
CHAPTER 10

Approved for Publication and Distribution

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Preface

This guide is issued by the Western Area Power Administration (Western) and is designed to provide specific guidelines, instructions, procedures, and criteria for performing insulating liquids testing in Western's electrical facilities. Procedures and guidelines are in accordance with established industry standards and current industry practices. Any corrections or comments concerning this guide may be addressed to the Western Area Power Administration, Division of Power System Maintenance, A6200, Golden, Colorado.

Interpretations

The stated interpretations for the following words shall be applied throughout this chapter:

- "May" - Permissive choice.
- "Shall or Must" - Mandatory under normal conditions.
- "Will" - Mandatory, but allowing the responsible employee or party some discretion as to when, where, and how.
- "Should" - Advisory. "Should" statements represent the best advice available at the time of printing.
- Male pronouns and related terms are used in reference to both male and female employees.

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Nomenclature

cubic feet per gallon	ft^3/gal
cubic meters per liter	m^3/L
degree Celsius	°C
degree Fahrenheit	°F
dyne per centimeter	dyn/cm
feet	ft
gallon	gal
gallon per hour	gal/h
gallon per minute	gal/min
gallon per pound	gal/lb
gram	g
hour	h
inch	in
kilogram	kg
kilogram per cubic meter	kg/m^3
kilopascal	kPa
kilovolt	kV
kilovolt per second	kV/s
liter	L
liter per hour	L/h
liter per kilogram	L/kg
liter per minute	L/min
meter	m
micrometer (micron - obsolete)	µm
milligram	mg
milliliter	mL
millimeter	mm
newton per meter	N/m
ounce	oz
parts per million	p/m
potassium hydroxide	KOH
pound	lb
pound per gallon	lb/gal
pound per square inch	lb/in^2
quart	qt
root mean square	rms
Saybolt universal second	Sus
square meters per second	m^2/s

Purpose and Scope

Insulating liquids used in transformers and circuit breakers require proper testing and maintenance to monitor their condition and maintain the required dielectric strength. Liquid insulation that has deteriorated may cause damage to equipment and become a hazard to personnel. Liquid insulation can be grouped into two broad categories, (a) mineral oil derived from petroleum, and (b) several new synthetic liquids.

Dissolved gas-in-oil analysis (DGA) of mineral oil, coupled with the recommended oil screen tests, can provide useful information for early detection of developing problems. If accurate information on the condition of the mineral oil is available as the oil deteriorates, it is possible to predict when the oil will exceed recommended limits, and what remedial action can be taken. Too frequently, the testing and purification of liquid insulation is done without due regard to certain important precautions. The purpose of this manual is to give a better understanding of the characteristics of insulating liquids and to establish an effective and uniform maintenance practice and criteria for tests and treatment.

Part 1 - Mineral Insulating Oil

1. Characteristics of Insulating Oil

1.1 Refining of Insulating Oil.

1.1.1 Acid Refining. Prior to mid-1973, insulating oils used by the electric utility industry were produced by acid refining of naphthenic crudes. Basically, acid refining removes undesirable components from the oil by using sulfuric acid to cause the impurities to form sludge. The acidic sludge is subsequently removed by a centrifuge, sulfonic and naphthenic acid salts are removed by neutralization, water and alcohol are removed by a steam “stripper,” and remaining polar contaminants are removed by a final fuller’s earth treatment. This process is costly, and disposal of the sludge has caused environmental concern and criticism. Environmental pressures have forced refiners to curtail acid refining and develop new refining techniques.

1.1.2 Hydrogen and Solvent Refining. Presently, two types of refining, hydrogen and solvent, are being utilized by several refiners. These methods are less wasteful, potentially cheaper, and involve fewer environmental problems than acid refining.

1.1.3 Artificially Inhibited Oils. Of concern in the use of hydrogen and solvent-refined insulating oils is the lack of experience and information on aging characteristics of oil in service, particularly as these characteristics pertain to the formation of sludge. For this reason, Western now permits the addition of an artificial oxidation inhibitor (DBPC, discussed in section 6.3) to new oil.

1.2 Specifications for Insulating Oil. A tabulation of the American Society for Testing and Materials (ASTM) test methods and test limits for chemical and physical characteristics of oil presently used in Western specifications is shown (table 1) for inhibited and uninhibited insulating oil furnished for use in new equipment. These data may also be used in preparing specifications for replacement or makeup oil if the following points are kept in mind:

- Table 1 is revised periodically to keep it current; therefore, the most current revision should be obtained from Headquarters, Division of Power System Maintenance, Lines and Substations Branch, A6210.
- Makeup oil must be compatible with the existing oil when the two are mixed, and this requirement should be included in the specifications. An example would be the mixing of naphthenic and paraffinic oils as stated in the 1988 Doble Conference minutes.

Table 1
Chemical and Physical Characteristics of Mineral Insulating Oil

Type of Test	ASTM Method	Test Limits		
		Maximum or Minimum	Inhibited	Uninhibited
Acidity	D-974-87	MAX	0.05 mg of KOH/g	0.05 mg of KOH/g
Color ASTM	D-1500-87	MAX	0.5	0.5
Corrosive Sulphur	D-1275-86		Pass	Pass
Dielectric Strength	D-877-87 D-1816-84	MIN MIN	30 kV 35 kV	30 kV 35 kV
Flash Point	D-92-85	MIN	145°C	145°C
Interfacial Tension	D-2285-85	MIN	45 dyn/cm	45 dyn/cm
Pour Point	D-97-87	MAX	- 40°C	- 40°C
Power Factor at 100° C	D-924-82	MAX	0.3%	0.3%
Power Factor at 25° C	D-924-82	MAX	0.05%	0.05%
Specific Gravity at 15.6° C **or API Gravity at 15.6° C**	D-1298-85 D-287-82		0.865-0.910 32.0-24.0	0.865-0.910 32.0-24.0
Viscosity at 37.8° C				
Kinematic	D-445-88, D-2161-87	MAX	12 m^2/s	12 m^2/s
Saybolt	D-88-81	MAX	65 Sus	65 Sus
Oxidation or sludge, Choice of:				
Oxidation life	D-943-81	MIN	-----	100 hours
Sludge at 72 hours	D-2440-88	MAX	-----	0.1%
Oxidation stability	D-2112-86	MIN	195 minutes	-----
Inorganic Chlorides and Sulfates	D-878-86		None	None
Water	D-1533-88	MAX	35 p/m	35 p/m
2,6 - Ditertiary Butyl Paracresol (DBPC)	D-2668-87	MIN	0.15%	—---
Polychlorinated Biphenyl (PCB) analysis	N/A		None	None

2. Deterioration of Insulating Oil

2.1 Effect of Oxygen on Oil. Moisture contamination is one of the most common causes of deterioration in the insulating quality of oil. This contamination can be eliminated by purification. A less rapid but more serious deterioration, the formation of acids and sludge, is caused by oxidation. Thus, the exclusion of oxygen is of prime importance. In open-breather transformers, the oxygen supply is virtually unlimited and oxidative deterioration is consequently faster than in sealed transformers. Atmospheric oxygen is not the only source of oxygen available for the oxidation of insulating oils; water also serves as a source of oxygen and; therefore, leaky gaskets increase the rate of oxidation and moisture contamination. The rate of oxidation also depends on the temperature of the oil; the higher the temperature, the faster the oxidative breakdown. This fact points to the importance of avoiding overloading of transformers, especially in the summertime. Oxidation results in the formation of acids in the insulating oil, and the formation of sludge.

2.2 Moisture in Oil. Water can be present in oil (a) in a dissolved form, (b) as tiny droplets mixed with the oil (emulsion), or (c) in a free state at the bottom of the container holding the oil. Dissolved water is not removed by centrifugal treatment; the filtration process can partially remove dissolved water if the filter papers are thoroughly dried before filtration and are replaced frequently. The dissolved water is best removed by complete treatment of the oil (oil reclamation process). Emulsification occurs when the tiny droplets unite to form larger drops which sink to the bottom and form a pool of free water. Emulsified water or water in the free state may be readily removed by filtering or centrifugal treatment.

The effect of moisture on the insulating properties of oil depends upon the form in which the moisture exists. A very small amount of emulsified water has a marked influence in reducing dielectric strength of oil (figure 1), whereas dissolved water has little or no effect on the dielectric strength.

The amount of moisture which can be dissolved in oil increases rapidly as the oil temperature increases (figure 2). Therefore, an insulating oil purified at too high a temperature may lose a large percentage of its dielectric strength on cooling because the dissolved moisture is then changed to an emulsion. Recommended temperatures for purifying oil are given in section 4.

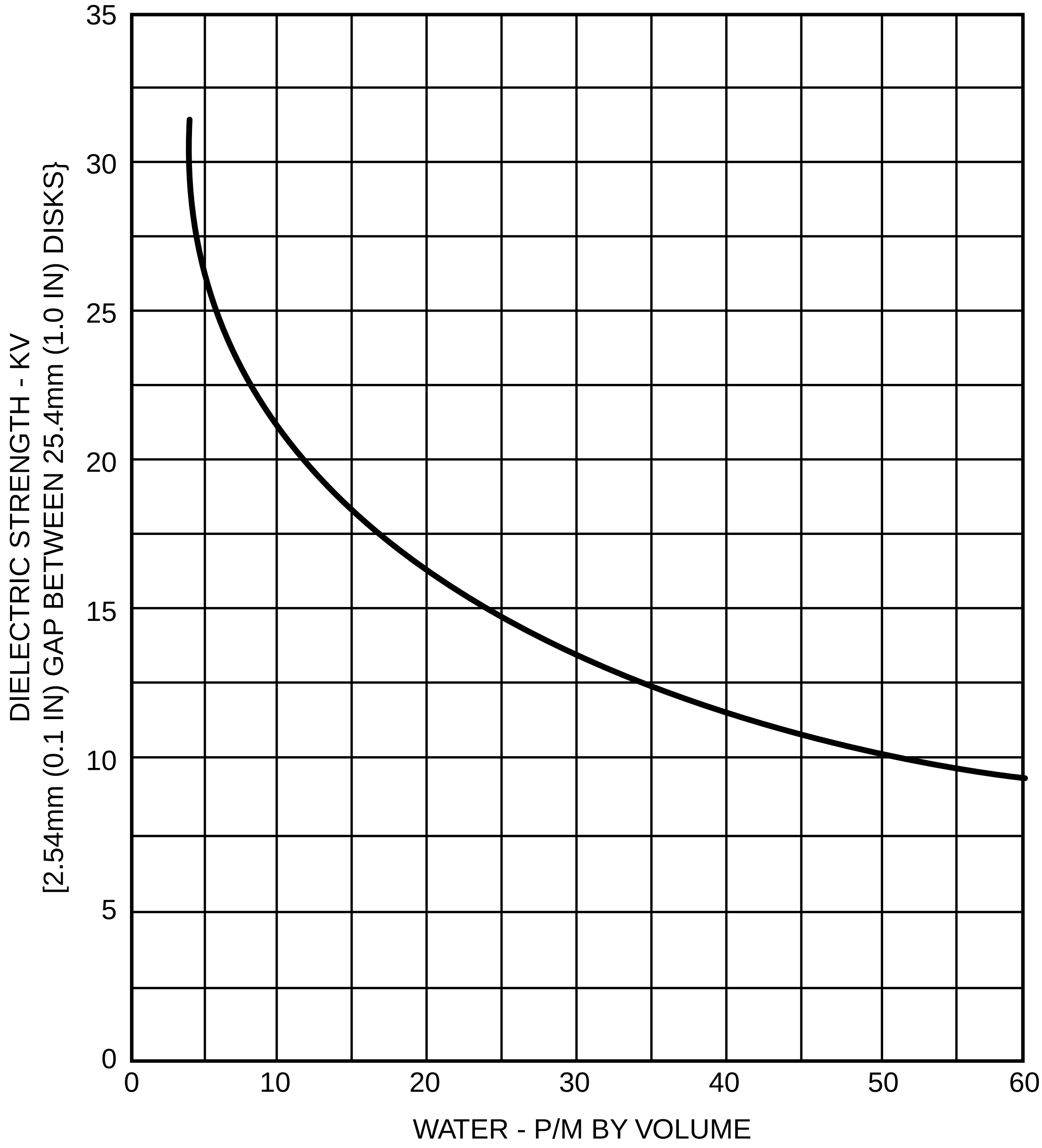

Figure 1
Relation Between Dielectric Strength and
Amount of Emulsified Water in Mineral Oil.

Source: Instruction Book of Insulating Oil for Electrical Apparatus,
Westinghouse Electric and Manufacturing Company No. I.B. 5336-D.

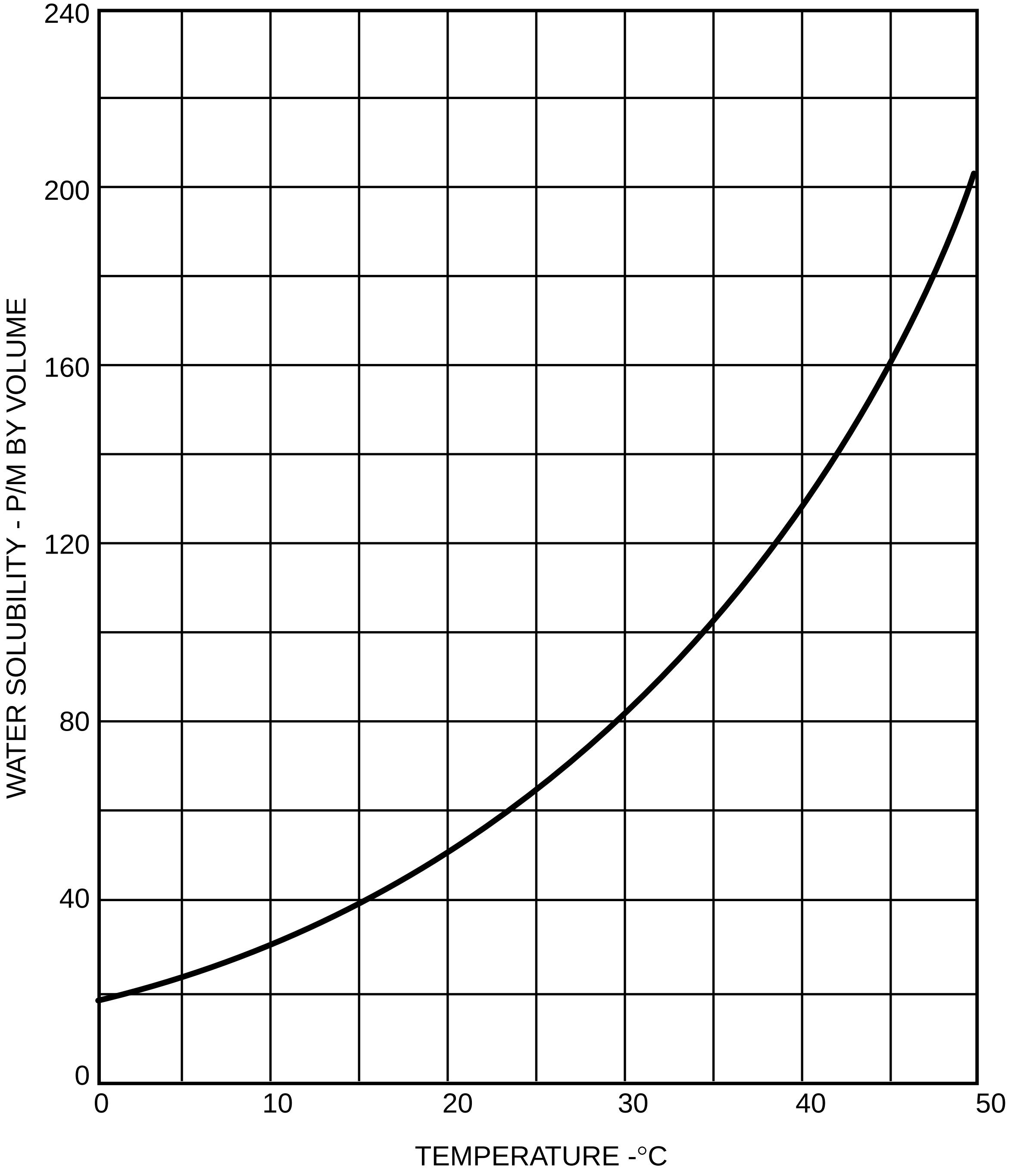

Figure 2
Maximum Amount of Water Dissolved in Mineral Oil as Affected by Temperature

Source: F.M. Clark, General Electric Company, Water Solution in High-Voltage Dielectric Liquids, Electrical Engineering, August 1940.

2.3 Oil Deterioration in Transformers. In transformers, sludge sticks to the surfaces through which heat is dissipated; the sludge forms a barrier to the flow of heat from the oil to the coolant and from the core and coils to the oil. If allowed to continue, the sludge may block off the flow of oil through the cooling ducts. As a result, the transformer insulating oil becomes hotter and the transformer could be damaged, particularly between the coil turns of the windings. Deterioration of the coil-turn insulation may eventually lead to short circuits between coil turns and the breakdown of the transformer. When oxidation progresses to the point where sludge is being precipitated, the first step should be to remove the sludge from the transformer by a high-pressure stream of oil and to either replace the sludged oil or treat it with activated clay to remove the acid and sludge precursors. Complete treatment of the oil is normally less costly than replacing it with new oil. Methods of treatment are described in section 4.

2.3.1 Absorption of Moisture by Insulating Materials. Solid insulation in transformers is very porous and absorbs much water. Some of the water that is dissolved in the oil is absorbed from the oil by the insulation. As more water is dissolved in the oil, more water is absorbed by the insulation. Once the water is absorbed by the insulation, it is difficult to remove. The most effective method for drying out the insulation in transformers is with heat and vacuum.

Sometimes a vacuum cannot be applied in the field. In this case, the transformer insulation must be dried by circulation of hot, dry oil. This oil should then be cooled and dried. Since the dielectric strength of insulation is reduced by moisture, it is important that steps are taken to prevent the introduction of moisture.

2.3.2 Absorption of Nitrogen by Oil. Special precaution should be taken when operating nitrogen-blanketed transformers to avoid bubbling the oil, due to the release of dissolved nitrogen when the pressure drops. Experience has shown that the automatic gas-pressure regulating system should be adjusted to limit the nitrogen pressure range from plus 3.4- to plus 21-kPa (plus 1/2- to plus 3-lb/in^2) gauge to avoid formation of these bubbles and subsequent troubles due to corona deterioration.

2.4 Oil Deterioration in Circuit Breakers. In circuit breakers, a spark flashes through the insulating oil during electrical interruption. If oxygen is available in any form, water and carbon dioxide will be formed. When the oxygen supply runs out, carbon particles and hydrogen are formed. The hydrogen is dissipated as gas. Carbon particles can be seen visually. The presence of carbon particles generally leads to trouble long before oxidative deterioration becomes significant.

3. Testing of Insulating Oil

3.1 Types of Oil Tests. Five basic tests on insulating oil, when considered collectively, give a reasonably accurate diagnosis with respect to the serviceability of an insulating oil. The tests are (a) dielectric, (b) acidity, (c) power factor, (d) interfacial tension (IFT), and (e) water content. Although these oil tests evaluate the insulating characteristics of the oil, the information gained from the analysis of these tests, coupled with DGA (see section 7), provide excellent diagnostic tools for monitoring and evaluating the operating conditions of the oil-filled equipment. Sampling procedures for these tests are described in appendix A.

3.1.1 Dielectric Test. The dielectric test measures the voltage at which the oil breaks down. The breakdown voltage is indicative of the amount of contaminant (usually moisture but may also be carbon or polar contaminants) in the oil, and the voltage should be checked frequently. The generally accepted minimum dielectric strength is 30 kV for transformers with a high-voltage rating of 287.5 kV and above and 25 kV for transformers with a high-voltage rating below 287.5 kV. New oil should test at least 35 kV by ASTM methods of testing. Appendix B contains a discussion of field dielectric test equipment and methods. The dielectric test will not indicate the presence of acids and sludge.

3.1.2 Acidity Test. If properly refined, new transformer oils contain practically no acids. The acidity test measures the content of acids formed by oxidation. The oxidation products polymerize to form sludge which then precipitates out.

Acids react with metals on the surfaces inside the tank and form metallic soaps, another form of sludge. Sludging has been found to begin when the acid number reaches or exceeds 0.4 mg of KOH/g (0.4 is considered to be the normal service limit). New oil has an acid number of less than 0.05 mg of KOH/g. The acid number (also referred to as the neutralization number) equals the milligrams of potassium hydroxide (KOH) required to neutralize the acid contained in 1 g of oil. It is questionable whether an oil that has deteriorated to the point where its acid number exceeds 0.6 mg of KOH/g can be restored to good condition by a single renovation. It is almost certain that two or more renovations, spaced 6 months to 1 year apart, would be necessary. It is recommended that an upper limit of 0.2 mg of KOH/g be used to determine when oil should be renovated, as at that point a single renovation would probably restore the oil to very good condition. Oil showing an acid number of 0.15 mg of KOH/g or larger can be expected to show accelerated acid formation (figure 3). Appendix C contains a discussion of field acidity test equipment and methods.

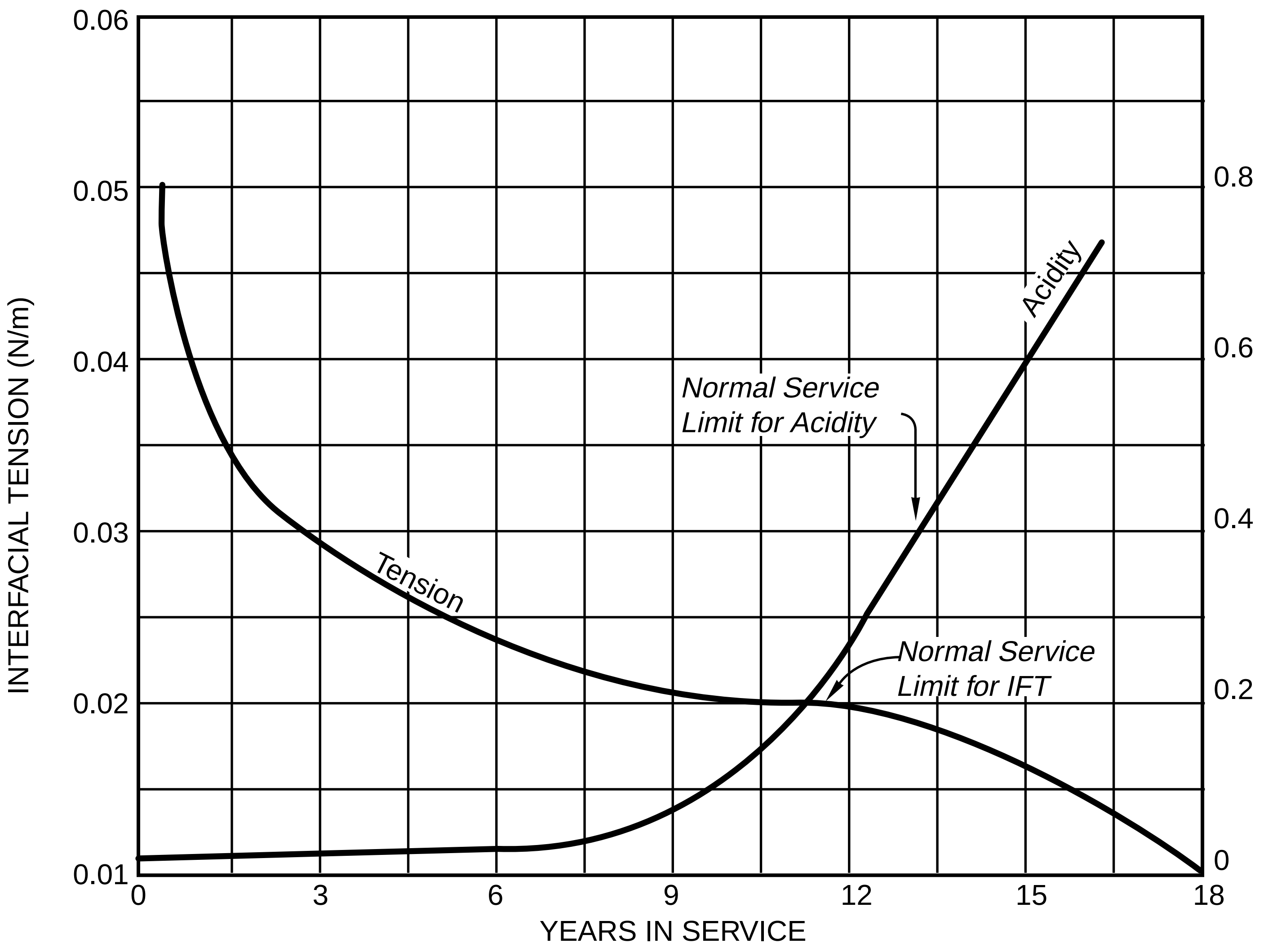

Figure 3
Relation Between Service Life, Interfacial Tension, and Acidity in Mineral Oil.

Source: AIEE Transactions, 1955, page 774.

Tests have been made which indicate that acidity is proportional to the amount of oxygen absorbed by the oil. It is estimated that 0.0015 m^3/L (0.2 ft^3/gal) of oxygen absorbed in oil will cause an acidity of about 0.4 mg of KOH, which is the approximate acidity number at which sludging is assumed to start. Based on this assumption and equal loading test cycles, the following table has been developed.

Transformer Type	**Approximate Time Period Before Sludging Begins**
Transformers with free air access	10 years
Transformers with conservators	15 years
Transformers bolted tight (sealed) with no nitrogen	50 years
Transformers with nitrogen over oil	67 years

While the above periods may not correspond to actual field examples due to different load conditions than those assumed, they do illustrate the relative periods of serviceability for the different types of transformers.

3.1.3 Power Factor Test. The power factor of an insulating oil equals the cosine of the phase angle between an alternating-current (ac) voltage applied to an oil and the resulting current. Power factor indicates the dielectric loss of an oil and, thus, its insulating value. The power factor test is widely used as an acceptance and preventive maintenance test for insulating oil. Oil power factor testing in the field is usually done with the Doble type MH or M2H test set in conjunction with power factor tests of the oil-filled equipment. Test procedures for the Doble instruments are given in appendix E.

The power factor of new oil should not exceed 0.05 percent at 25°C. A high power factor in used oil indicates deterioration or contamination or both with moisture, carbon, varnish, Glyptal, sodium soaps, or deterioration products. Used oil with a power factor in excess of 0.5 percent should be further analyzed in a laboratory to determine the cause of the high power factor. Oil with a power factor in excess of 2.0 percent may constitute an operational hazard. It should be further investigated and either reconditioned or replaced.

3.1.4 Interfacial Tension (IFT) Test. The acidity test determines conditions under which sludge may form, but does not necessarily indicate that actual sludging conditions exist. The IFT test is employed as an indication of the sludging characteristics of power transformer insulating oil. It is a test of interfacial tension of water against oil, which is different from the surface tension of oil against air. The attraction between the water molecules at the interface is influenced by the presence of polar molecules in the oil in such a way that the presence of more polar compounds causes lower interfacial tension.

The test measures the concentration of polar molecules in suspension and in solution in the oil and thus gives an accurate measurement of dissolved sludge precursors in the oil long before any sludge is precipitated. It has been established that an interfacial tension of less the 0.015 N/m (15 dyn/cm) almost invariably shows sludging. An IFT of 0.015 to 0.022 N/m (15 to 22 dyn/cm) shows an uncertain condition, and an IFT value of more than 0.022 N/m (22 dyn/cm) is generally indicative of no sludging. Transformer oils whose IFT is in the range of 0.015 to 0.022 N/m (15 to 22 dyn/cm) should be scheduled for reclaiming, regardless of acidity values. Appendix D contains a discussion of field IFT test equipment and methods.

3.1.5 Water Content Test. A low water content in insulating oils is desirable in order to achieve an adequate electrical strength and low dielectric losses. Low water content maximizes the life of the insulation system and minimizes metal corrosion. ASTM test method D-1533-88, "Test for Water in Insulating Liquids (Karl Fischer Method)," is based on the reduction of iodine by water and sulfur dioxide (figure 4).

Water content in transformer oil is of greater concern than water content in breaker oil, simply because of the effects.

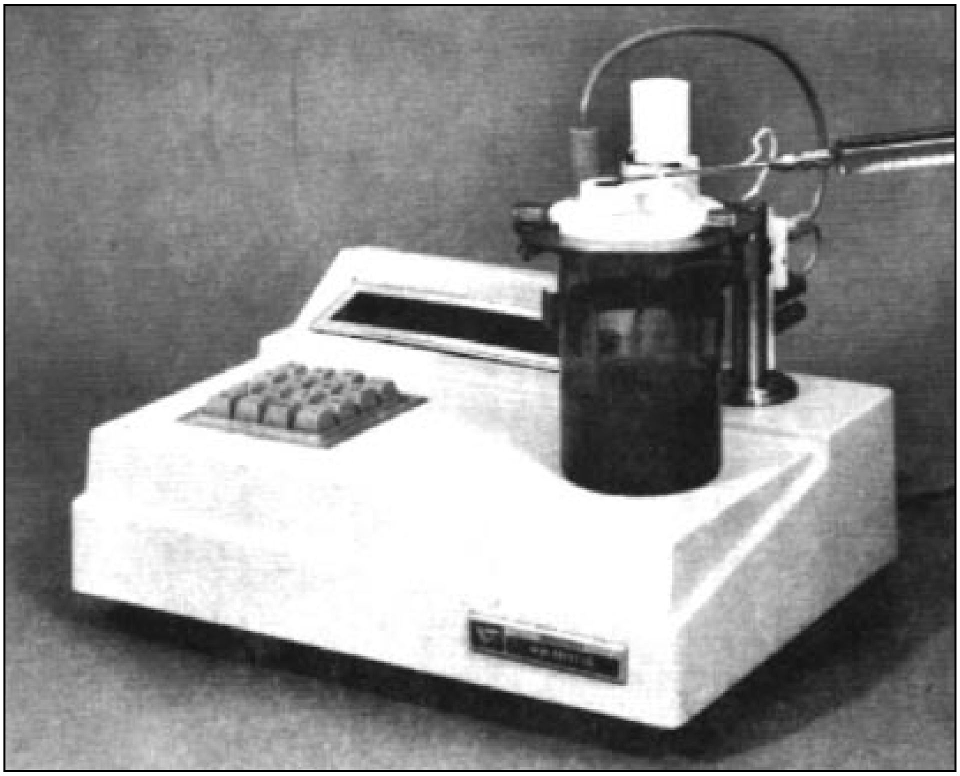

Figure 4
A Photovolt Aquatest-IV Determines
Water Content

Courtesy of Sierra Nevada Region.

3.1.6 ASTM D-3487-88, Test Limits. Table 1 specifies the characteristics and test requirements for new mineral oil used in electrical apparatus.

3.2 Interpretation of Test Results. When the results from all five tests are integrated, a sound conclusion can be drawn as to the condition of the oil. Qualitative relationships exist between acidity and IFT (figure 3) which are useful in interpreting test results. Note that the rate of change of IFT is a more sensitive indication of early stages of deterioration. The IFT measurements are particularly useful in judging the effectiveness of oil renovation processes; identifying at an early stage new oil with poor life expectancy, thus, permitting treatment while it is still practical; and indicating when oil should be discarded and replaced. The rate of change of acidity is often a more sensitive indication of deterioration near the sludge point. However, this is only true if the oil does not contain alkali impurities. Such impurities neutralize the acids as they are formed, resulting in a low-acidity value.

3.3 Periodic Testing Program

3.3.1 Field Test Schedules. From the aspects of safety, continuity of service, and efficient, low-cost maintenance, it is desirable to monitor the condition of insulating oil by testing and to take remedial measures before the oil reaches a point of deterioration beyond which failure of equipment may occur.

The establishment of and adherence to a comprehensive oil testing program can:

- Indicate abnormal conditions in oil-filled equipment.
- Provide information regarding deterioration trends.
- Reveal incipient problems which can be detected early enough to avoid an unscheduled outage.

Therefore, it is recommended that the inservice oil in transformers and breakers be tested annually.

The condition of the oil and the load conditions should determine whether a more frequent schedule should be followed. Normally, acidity, IFT, power factor, water content, and dielectric tests should be made on oil in transformers, and power factor and dielectric tests should be made on oil in circuit breakers at least once a year. Permanent records should be kept of all test results. Whenever the test results show that accelerated deterioration is occurring, more frequent oil tests should be made to further assess the conditions and determine the appropriate corrective action. For example, when the IFT reaches a value of 0.025 N/m (25 dyn/cm), more frequent testing is required to determine when the IFT value is approaching 0.022 N/m (22 dyn/cm) and the oil should be scheduled for reconditioning.

Idle, oil-filled equipment may also accumulate moisture and should be tested at least once a year. The cooling coils of water-cooled transformers sometimes develop leaks, and water may enter the oil so fast that even weekly dielectric tests would not catch the trouble. A rise in the transformer oil level is the best indicator for this condition. Most water-cooled transformers are equipped with cooling tubes of double-wall construction. The intent of this construction is to bleed off any leaking water or oil into the space between the two walls of the tube to avoid contamination. Usually, the oil pressure is maintained higher than the water pressure, and a double-wall leak causes oil to be lost into the cooling system discharge. The loss would be indicated by low oil level in the transformer. Hence, change of oil level is an important indication and should be checked frequently. Distribution transformers need not be tested. However, station service transformers of larger capacity need to be tested as frequently as once a year.

The presence of carbon in circuit breakers and step-voltage regulator oil introduces a hazard due to the tendency of the carbon to lower the dielectric strength of the oil and also to form deposits on insulating surfaces, reducing the insulation resistance. Carbonized oil is more vulnerable to moisture than clean oil. The quantity of carbon is proportional to the number and severity of the arcs interrupted. Samples of oil for dielectric test should be obtained from both types of equipment (circuit breakers and step-voltage regulators) annually during the partial service and from oil circuit breakers after a heavy fault or series of faults. If an oil sample is black from suspended carbon, the oil should be filtered or centrifuged even though the dielectric test is good.

3.3.2 Laboratory Testing. The decision to remove moisture to increase dielectric strength of oil by standard reconditioning methods should be made by field personnel. A sample of oil which appears to be in poor or questionable condition due to contamination other than moisture should be examined by a laboratory. The decision to reclaim, replace, or order additional laboratory tests will be made by field personnel. Appendix A contains sampling procedures.

4. Reconditioning Used Insulating Oil

4.1 Natural Precipitation. Oil that has low dielectric strength or contains deposits of sludge or other contamination requires attention. Low dielectric strength indicates the need for drying by a mechanical filter or vacuum dehydrator. High acidity, high power factor, or low IFT values indicate the need for treatment. When used insulating oils are to be subjected to reconditioning or reclaiming processes or both, every advantage possible should be taken of natural precipitation. Considerable savings can frequently be realized in processing used oil if it is allowed to remain in its container undisturbed for at least 24 hours so that water and suspended solids can settle out. The oil can then be removed without disturbing the residue in the bottom of the container, thus, it becomes unnecessary to remove this residue from the processing machinery.

4.2 Filter Presses. Filter presses vary in form but are based upon the principle of forcing oil under pressure through a series of absorbing and filtering materials, such as paper. Filters of this type are capable of removing carbon, free water, sludge, etc., in suspension. Except for certain special arrangements, filter presses cannot remove these contaminants effectively when they are dissolved or in colloidal form. These devices (particularly those with centrifuges) will not remove air but, in fact, tend to aerate the oil.

Experience has shown that the most efficient temperature at which to filter insulating oil is between 20 and 40°C (68 and 100°F). Below 20°C the viscosity increases rapidly, while at temperatures above 40°C, the moisture is more difficult to separate from the oil.

4.2.1 Filter Press Operation. When the oil is to be purified by the use of a filter press using blotting paper, the paper should be well dried to obtain the most efficient operation; otherwise, the paper may actually add moisture to the oil. If convenient, an oven should be used for drying the paper, and the sheets should be separated as they are hung on rods in the oven to permit free circulation of air and to ensure the most rapid drying. The filter paper should be dried from 6 to 12 hours at a temperature of 101 to 105°C (214 to 220°F). After drying, the paper should be taken from the oven directly to the filter, or it may be stored in dry transformer oil for future use. When transferring the paper, handle it as little as possible to avoid the absorption of moisture from the hands and air.

During purification, sludge or small carbon particles clog the filter paper and cause considerable back pressure. When the back pressure reaches 517 kPa (75 lb/in^2), the paper should be replaced.

When cleaning circuit breaker oil containing a large amount of free carbon, the accumulation of sediment on the surface of the paper makes frequent replacement of the paper necessary. In such cases, it is more economical to remove only the sheet of paper nearest the oil inlet frame in each section (the solid matter collects there) and insert the replacement sheet at the discharge end of the stack.

When purifying very wet oil with a filter press, extra absorbent filter paper should be used. As the filter paper absorbs moisture, the back pressure will increase appreciably. Therefore, the operator should carefully monitor the inlet pressure gauge. If a sharp rise occurs, stop the process and change the filter paper.

4.3 Cartridge Filters. In recent years, Western has purchased mobile cartridge-type filters for reconditioning transformer and circuit breaker oil. The most popular of these units are the AMF “Cuno-Pore” and the Alsop “Hy-Speed” filters. These units are available in various sizes with oil-processing capacities ranging from 37.8 to 284 L/min (10 to 75 gal/min) and utilize disposable cartridges with filter densities ranging from 1 to 25 µm. (Note: The 6-µm filters are recommended for transformer oil; and 6- to 10-µm filters for circuit breaker oil.) These mobile filter units are smaller, lighter, and more portable than large filter presses; have greater oil-flow capacities, and in most cases, provide better water and particle removal. In addition, no drying oven is required since the filter cartridges are hermetically sealed in plastic for shipment and storage.

4.4 Centrifuges. Another means of separating free and suspended contaminants, such as carbon, water, sludge, etc., from oil is the continuous centrifuge. In general, the centrifuge can handle much greater concentrations than can the conventional filter press, but it cannot remove some of the contaminants as completely as a filter press. Consequently, the centrifuge is generally used for rough-bulk cleaning where large amounts of contaminated oil are to be handled. Frequently, the output of the centrifuge is put through a filter press for the final purifying. The centrifuge cannot remove dissolved water from oil since the centrifuge is sealed with water, the oil leaving the centrifuge may be saturated at the temperature of operation and conceivably could contain more dissolved water than when it entered. Neither the centrifuge nor the filter press is designed to treat oil chemically.

4.5 Coalescers. Coalescers are used to remove free water from both lubricating and insulating oils. Coalescing filtration is a relatively new technique that has been borrowed from the aviation fueling field. Fiberglass cartridges trap small water particles. Increasing differential pressure across the filter media forces the particles of water together, and the large water drops are extruded at the outer surface of the fiberglass element. Large water drops are retained within a water-repellent separator screen and collect, by gravity, at the bottom of the filter while dry oil passes through the separator screen. This method is quite similar to centrifuging with respect to performance and limitations. Coalescing filters have no moving parts, and therefore, are simpler in operation and maintenance than centrifuges; however, any particulate matter in the oil will clog a coalescer and render it useless.

4.6 Vacuum Dehydrators. The vacuum dehydrator is efficient in reducing the water content of an insulating oil to a very low value. In this apparatus, the oil is exposed to a vacuum and heat for a short interval of time. Vacuum dehydrators can be used to treat oil without removing associated equipment from service. In addition to removing water, vacuum dehydrators will degas the oil and remove the more volatile acids. Vacuum dehydrators are frequently used by the manufacturer during initial filling of new transformers.

4.7 Electrostatic Oil Filters. Electrostatic oil filters are lightweight and portable. These systems remove water, particulates, and polar contaminants from insulating oil by a unique nonionizing-electrostatic filtration method. One manufacturer states that the filter is capable of dehydrating oil below 10 p/m absolute, and removing salt and submicronic particulates without affecting the concentration of additives in the oil. Particles are entrapped within the electrostatic filter in three distinct ways: (1) electrostatic attraction and containment of particles to the grid elements, (2) mechanical bonding (impaction) of particles to the grid elements, and (3) entrapment of contaminants between grid elements. When contaminated, the grids are removed as a unit, rinsed in solvent, and reinstalled. For oil containing a substantial quantity of free water, a coalescing filter should be used upstream of the electrostatic filter. A combination of these filters is claimed to achieve an oil dielectric strength in excess of 40 kV in a single pass.

4.8 Treatment of Circuit Breaker Oil. Although it is customary to recondition circuit breaker oil in much the same manner as transformer oil, the contamination is somewhat different. Whereas sludging is, or may be, the principal problem in transformer oil, this is not the case with circuit breaker oil. Conditions conducive to sludge formation and other deleterious effects produced in transformers do not normally occur in circuit breakers. Aside from being a dielectric, the chief function of transformer oil is to dissipate heat, but, in a circuit breaker it is to quench the arc. Extinguishing arcs can result in chemical breakdown and the formation of minute particles of carbon which reduces the dielectric strength of the oil. If present in sufficient quantity, these particles will deposit or settle onto insulating members until a short circuit results.

Testing methods for circuit breaker oils are the same as those used for transformer oils. The chief problem in circuit breaker oil maintenance is to keep the oil free of water, conducting products, and other contaminants. A filter press or cartridge filter is the accepted method of reconditioning.

The presence of carbon in oil increases the susceptibility of the oil to deterioration due to moisture, thereby increasing the rate at which the oil loses dielectric strength. For certain oil-poor circuit breakers where the carbonizing effects are severe and frequent treatment is required, it is more practical to replace the oil than try to filter it since the quantity of oil lost is relatively small.

4.9 Treatment of Tap Changer Oil. The oil used in load-tap changing compartments or in step-voltage regulators is usually the same type as that used in transformers. The maintenance of this oil is fundamentally the same as that used in circuit breakers. However, there is a contaminant sometimes present in oil exposed to this type of service that does not exist to any great extent in circuit breaker oil. The comparatively large number of operations of the contacts in this type of device is quite likely to produce a considerable amount of very fine copper dust. This can be removed by the same filtering methods used on circuit breaker oils, however, precautions should be taken if the presence of these fine copper particles in the oil will harm reconditioning equipment. Rotary pumps with close clearances can be seriously damaged if copper particles are allowed to pass through them. Also, copper is an oxidation catalyst which increases the rate of oil deterioration. Due to this oxidizing characteristic and the difficulty involved in removing these copper particles prior to entrance into the pump, it is usually desirable to replace the oil with new oil. However, it is possible to reclaim the contaminated oil if necessary.

4.10 Inservice Oil Filtering. Several electric utilities have successfully utilized inservice oil-filtering systems on transformer tap changers and oil circuit breakers used for capacitor and reactor switching. Inservice filtering is reported to remove many of the carbon and copper particles from the oil and thus greatly extend the interval for oil reconditioning and equipment maintenance. A typical installation consists of a permanently mounted pump of 11.4-L/min (3-gal/min) capacity and truck-type oil filter of 19-L (20-qt) capacity using 2-µm filter elements. Daily filtering periods may be controlled with a time switch or be interconnected with the switching operation.

4.11 Limited Interchangeability of Oils. As a normal practice, used or reclaimed circuit breaker oil must not be used in a transformer. The primary reason is the difficulty involved in removing arc and oxidation products while maintaining resistance to sludging. On the other hand, oil used in a transformer can be transferred to a breaker, in which case, the oil should pass tests for circuit breaker oil, as previously outlined.

4.12 Disposal of Oil. It is recommended that all insulating oil which is excess or is no longer suitable for use in electrical apparatus be tested for PCB contamination prior to disposal. Its disposal must be in accordance with Federal and state rules and regulations.

5. Reclaiming Used Insulating Oil

5.1 Fuller's Earth Method. Fuller's earth is the material most frequently used for reclaiming oils. Fuller's earth is a natural clay mined near Attapulgus, Georgia; and Ocala, Florida. Chemically, it is crystalline hydrated magnesium aluminum silicate, with a unique chain structure which gives it unusual colloidal and absorptive properties. The most common reclaiming method is by gravity or pressure percolation of oil through 300-180 or 212-163 µm sieve (50-80 or 70-90 mesh), with fuller's earth at a rate of 0.06 to 0.12 kilograms of earth per liter of oil (1/2 to 1 lb/gal) with associated mechanical filtration and vacuum dehydration equipment.

5.1.1 Portable Oil Reclaiming Units. Oil reclaiming units such as a Bowser (Keene Corp.) are designed to process oil at a rate of about 2,270 L/h (600 gal/h) and utilizes bulk fuller's earth in dual tanks of 68-kg (150-lb) capacity each. These units are equipped with oil heaters, utilize "Cuno-Pore" (AMF, Inc.) cartridge filters, employ high vacuum systems for removing moisture and gas, and provide a method of introducing Ditertiary-Butyl Paracresol (DBPC) into the processed oil (see section 6.3). These units may be used to reclaim oil in energized transformers and when so used, the flushing action removes carbon and sludge deposits from the transformer coils, core, radiators, and tank. Portable instruments for measuring dielectric strength, power factor, IFT, and moisture content are used to determine the optimum end point for the reclaiming process.

5.2 Activated Alumina Method. Activated alumina has been successfully used by several electric utilities in recent years for inservice transformer drying. This process is relatively simple and economical, although it requires considerably more time than the vacuum dehydrators described above. The process involves continuous forced circulation of oil from the top of the transformer through a tank of activated alumina and back into the bottom of the transformer over a prolonged period of time (3 to 6 months or longer). The activated alumina absorbs water from the oil on contact, and the relatively dry oil then extracts moisture from the core and coil insulation. At the same time, acids, polar contaminants, and particulate matter, such as colloidal carbon, are removed from the oil through chemical action. A typical drier system consists of a steel tank about 0.9 m (3 ft) high and 0.6 m (2 ft) in diameter holding approximately 227 kg (500 lb) of grade F-3, 2.36-1.40 mm sieve (8-14 mesh) activated alumina, an oil pump with a flow rate of 3.8 to 19 L/min (1 to 5 gal/min), and associated valves and piping. A check valve is installed at the bottom transformer connection to prevent draining the transformer in the event of a leak in the drier system. A silica-gel breather is installed on free-breathing, conservator-type transformers to prevent additional moisture from entering the transformer. The activated alumina charge is changed every 2 to 3 months.

6. Oxidation Inhibitors for Insulating Oil

6.1 Natural Inhibitors. New insulating oil, as normally refined, contains small amounts of certain chemical compounds that act as oxidation inhibitors. These naturally occurring materials retard oil oxidation until such time as they are expended. The rate at which the inhibitors in oil are used up is dependent upon the amount of oxygen available, soluble contaminants in the oil, catalytic agents in the oil, and the temperature of the oil. In modern transformers, either sealed to exclude air and moisture or protected by an inert atmosphere, the benefits of the inhibitors can be extended over many years. As the inhibitors are exhausted, the rate of oxidation and the deterioration of the oil increases. Reclaiming processes, such as acid refining or clay treating, can restore the oil so that it has most of its original characteristics, but this has no effect upon restoring the usefulness of the natural inhibitors occurring in the oil. In fact, both fuller's earth and activated alumina remove the natural inhibitors and the reclaimed oil has no resistance to oxidation. To overcome this undesirable condition, synthetic oxidation inhibitors should be used to extend the life of the reclaimed oil.

6.2 Inhibitor Action. A number of organic chemical compounds are known to slow down the oxidation when added to lubricating or insulating oils. Such additives are known as antioxidants or oxidation inhibitors. Unfortunately, all known oxidation inhibitors become depleted with time. When all of the inhibitor has been used up, the oil starts to deteriorate again, and deterioration proceeds in the same way and at the same (or greater) rate as in an uninhibited oil. The useful life of the oil is extended by the amount of time the inhibitor remains effective, usually a few years.

6.3 The DBPC Inhibitor. An inhibitor material that has found almost universal approval is known, chemically, as 2,6-ditertiary-butyl paracresol, but is generally referred to as DBPC. This material is a very desirable inhibitor and has outstanding properties which, even in small concentrations, are a stable and effective oil antioxidant. Since the natural inhibitors are consumed by oil in service and are completely removed by fuller's earth, it is important and necessary that following the reclaiming process, an inhibitor, such as DBPC, be added to the oil. Reclaimed oil should be tested for DBPC content. DBPC is commercially available in a concentrated oil solution or in dry-flake form which must be dissolved in hot transformer oil before use. A concentration of 0.3 percent DBPC by weight is recommended (table 2). Since DBPC is nonpolar and insoluble in water, it is not removed from the oil by fuller's earth treatment if the temperature is kept below 75°C (167°F).

6.3.1 Sample Problems. A transformer contains 800 L (211 gal) of oil. It is desired to inhibit the oil in the transformer with 0.3 percent by weight DBPC antioxidant.

6.3.1.1 To Use IMPRUVOL-20. The addition of 0.3 percent by mass of DBPC antioxidant (table 2) to transformer oil corresponds to 15-L IMPRUVOL-20 per 1,000 L (91.5 gal-IMPRUVOL-20 per 100 gal) of transformer oil. Since the transformer contains 800 L (211 gal) of oil, multiply 15 L by 0.8 (1.5 gal by 2.11) which gives 12 L (3.17 gal) of IMPRUVOL-20 necessary to provide 0.3 percent DBPC antioxidant concentration in the transformer.

Table 2
Effective DBPC Antioxidant Concentration of IMPRUVOL 20 (Koppers Co.)

Percent DBPC antioxidant by mass desired in transformer oil	Kilograms DBPC antioxidant per 1,000 liters transformer oil[1]	Pounds DBPC antioxidant per 100 gallons transformer oil[1]	Liters IMPRUV 20 per 1,000 liters transformer oil[2]	Gallons IMPRUVOL 20 per 100 gallons transformer oil[2]
0.1	0.9	0.7	5.0	0.5
0.2	1.8	1.5	10.0	1.0
0.3	2.6	2.2	15.0	1.5
0.4	3.5	3.0	20.0	2.0
0.6	5.3	4.4	30.0	3.0
0.8	7.0	5.9	40.0	4.0

[1] Density of typical transformer oil - 876 kg/m^3 (7.31 lb/gal).

[2] Density of IMPRUVOL 20 - 896 kg/m^3 (7.48 lb/gal).

6.3.1.2 To Use Flake DBPC Antioxidant. To compute the amount of flake DBPC antioxidant needed, take 2.6-kg DBPC antioxidant per 1,000-L (2.2-lb DBPC antioxidant per 100 gal) transformer oil, from table 2, which corresponds to a level of 0.3 percent DBPC antioxidant inhibition. Multiply this figure by 800 L/1,000 L (211 gal/100 gal). The result is 2.08-kg (4.64-lb) DBPC antioxidant for the transformer.

The volume of transformer oil required to prepare a 20-percent by mass DBPC antioxidant oil solution for adding 2.10 kg (4.64 lb) of DBPC antioxidant to the transformer is obtained by multiplying 2.10 kg (4.64 lb) by the factor 4.57 L/kg (0.55 gal/lb) to give 9.6 L (2.55 gal). If the mass of transformer oil for preparing this solution is required, multiply 2.10-kg (4.64-lb) DBPC antioxidant by the factor 4 to give 8.42 kg (18.6 lb) of oil.

7. Testing for Combustible Gases in Power Transformers and Regulators

The chemical decomposition of materials within transformers generates combustible gases. Degradation by excessive heating or electrical discharges is very common. The severity of gassing depends on the nature of the problem, which can range from low-level corona or overheating to total insulation failure. The combustible gas test has proven to be a particularly valuable means of detecting overheating or incipient low-energy faults in transformers and regulators since such problems normally cannot be detected by electrical tests. Early detection of problems is particularly important because it allows time for planned corrective action to be taken and, therefore, minimizes the chances of damage to the units and emergency outages. Western presently analyzes inservice transformer oil for content of combustible gases using combustible gas analyzers and gas-in-oil analysis by gas chromatography.

7.1 Combustible Gas Analyzers. Most field offices have acquired and used combustible gas analyzers to test periodically for an indication of internal conditions in power transformers and regulators with a nitrogen seal or constant pressure system. In several cases, incipient problems have been detected and corrective action has been taken in an economical and timely manner. This section gives guidelines for use of this valuable technique as a periodic maintenance tool.

It has been established that electrical problems in transformers are invariably accompanied by the generation of a variety of combustible gases which result from the local decomposition of the surrounding insulated materials.

To utilize gas generation as an indicator of incipient malfunction, the detector should be specifically designed for combustible gas detection. Quantitative tests can be satisfactorily made using either a portable gas detector or a combustible gas indicator. Where continuous combustible gas monitoring is necessary and justified, a fault gas recorder has the capability of performing this type of service. The recommended program for the performance of quantitative testing for total combustible gas is shown in table 3 for power transformers and regulators with nitrogen seal or constant pressure system.

To facilitate gas sampling, all equipment having a nitrogen blanket should have a gas sampling line installed from the upper portion of the tank to a ground-level sampling valve.

Table 3
Quantitative Testing for Total Combustible Gas

Percent Combustible Gas	Evaluation
0 - 1	Check each transformer or regulator every 12 months.
1 - 2	Equipment shows some indication of contamination or slight incipient fault. Readings in this range should be followed immediately with a dissolved gas analysis. Take readings at 3- to 6-month intervals to establish a trend.
2 - 5	Take readings at monthly intervals. If trend continues upward, prepare to investigate cause, preferably by internal inspection.
Greater than 5	Remove equipment from service as soon as possible. Investigate by internal inspection. Prepare to move equipment to service shop.

7.2 Dissolved Gas-In-Oil Analysis. Western has been conducting gas-in-oil analysis of insulating oils by gas chromatography and has had excellent results with this testing program. The gas-in-oil analysis is more sensitive than the total combustible gas analyzer and can detect transformer problems earlier because of the following:

- The combustible gases are all very soluble in oil, and there is little tendency for them to migrate into the gas space if the concentration is low.
- Normal oil circulation dilutes the gases as they are formed and there is no appreciable release into the nitrogen gas blanket until the gases saturate the oil.
- Certain important gases (for example, acetylene) exhibit such high affinities for oil that they are not easily released. Therefore, an analysis of free gas from transformers may be quite misleading in terms of the actual decomposition products.

The dissolved gas-in-oil analysis test procedure (figure 5) has proven to be predictive and valuable. Therefore, it is recommended that gas-in-oil analysis tests be performed on all Western transformers containing insulating oil.

The frequency of testing transformer oil using the DGA technique is an essential part of Western's preventative maintenance program and should follow the testing schedule listed below:

(1) As soon as possible after installation, preferably before initial energization.

(2) One week after initial energization.

(3) Three weeks after initial energization.

(4) Two months after initial energization.

(5) Six months after initial energization.

(6) Every year as a normal routine sampling cycle.

(7) If, however, a malfunction is suspected, the interval should be shortened as appropriate.

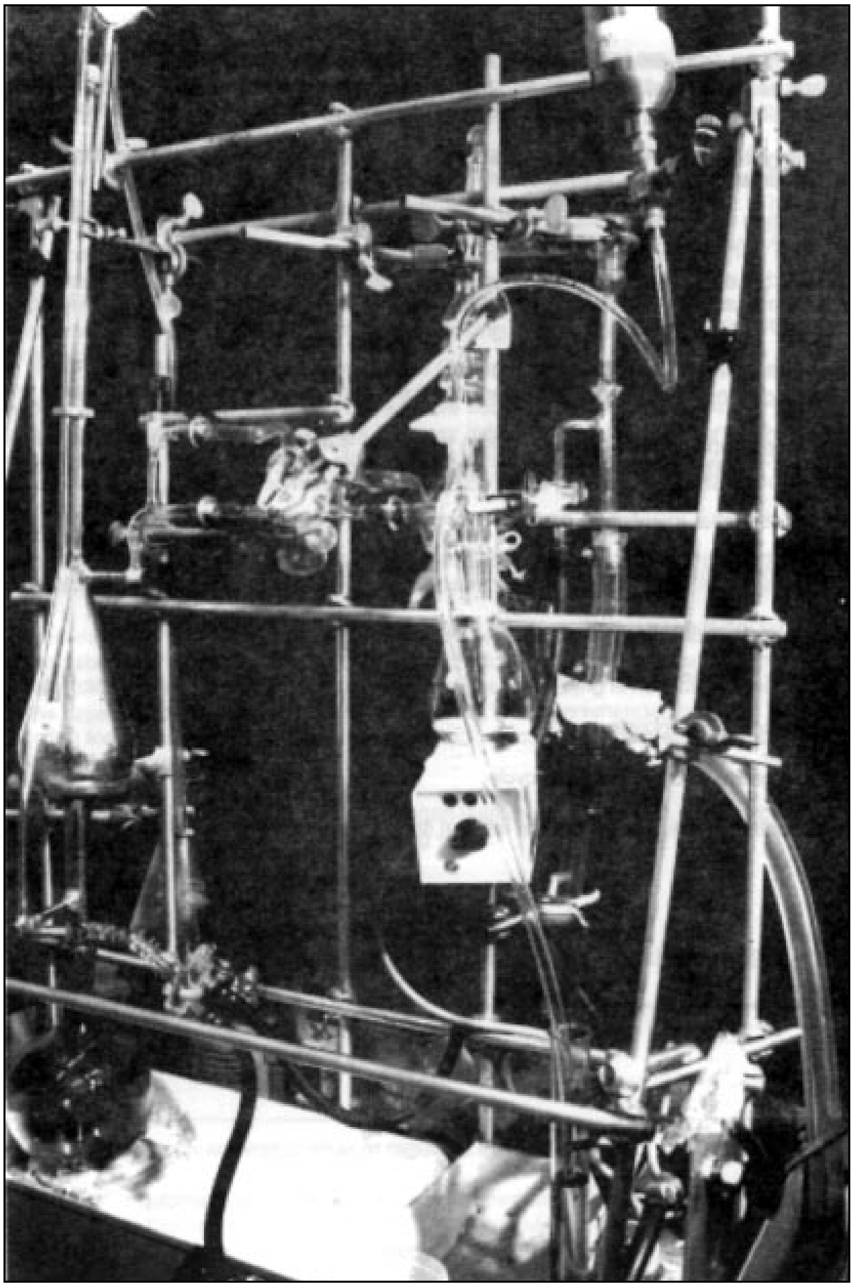

Figure 5
Dissolved Gas-In-Oil Extraction Apparatus

Courtesy of Sierra Nevada Region.

Part II - Synthetic Insulating Liquids

8. Silicone Oil

Polydimethylsiloxane Fluid (silicone oil) has been accepted by the Occupational Safety and Health Administration (OSHA) as a substitute for askarel. This synthetic fluid compares favorably with askarel and oil for use as a coolant, with a fire safety rating better than oil but slightly less than askarel. The viscosity of silicone fluid is higher than that of oil or askarel. Although long-term health studies have not been completed, the test data available indicate that the silicone fluid does not have the serious health effects associated with askarel. Because of the lack of definitive knowledge of the long-term effects, it is suggested that chronic exposure of a continuous nature be avoided whenever possible. The main health problem known is the potential eye irritant effects of silicone and the fact that it can be easily transferred to the eyes since it does not readily wash off the hands. It is therefore suggested that the following precautions be taken:

- Employees should be warned that the substance is not removed by ordinary soap and water and that transfer to the eyes can cause irritation.

- Labels containing the above warning and instructions for removal from the skin should be on every container.

9. Retrofilling Transformers With Silicone Oil

Several companies are retrofilling oil- and askarel-filled transformers with silicone fluid. The following items must be taken into consideration if a retrofill is desired:

- Due to the higher viscosity, the heat transfer of silicone is not as good as oil or askarel. Therefore, to avoid a higher temperature, a transformer will either have to be derated or provided with additional cooling capacity.

- Where direct substitution of silicone liquid is made for oil or askarel in a transformer, the loading capability of the transformer may be reduced up to 10 percent.

- Some types of pumps will wear very rapidly when used to pump silicone fluid. Acceptability of a pump must be checked for service as a transformer-silicone-oil pump.

- Gasket and bushing combinations used with askarel and transformer oils, such as cork and asbestos-impregnated cork, are compatible and are not injured by silicone fluid. Conventional silicone rubber gaskets and bushings cannot be used with silicone oil because they swell excessively.

- Silicone-filled transformers require no special maintenance and standard maintenance procedures developed for oil- or askarel-filled transformers will generally apply.

- Residual PCB in askarel-filled transformer will not leach out into the silicone fluid where it could be filtered out or otherwise removed. As a result, the transformer itself will remain a PCB item as far as disposal requirements are concerned.

It is suggested that any field office considering a change to silicone oil consult with the transformer manufacturers or other expert sources for advice.

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Test Method for Acid and Base Number by Color-Indicator Titration, ASTM Std. D-974-87.

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Test Method for ASTM Color of Petroleum Products (ASTM Color Scale), ASTM Std. D-1500-87.

Test Method for Corrosive Sulfur in Electrical Insulating Oils, ASTM Std. D-1275-86.

Test Method for Density, Relative Density (Specific Gravity), or API Gravity of Crude Petroleum and Liquid Petroleum Products by Hydrometer Method, ASTM Std. D-1298-85.

Test Method for Dielectric Breakdown Voltage of Insulating Liquids Using Disk Electrodes, ASTM Std. D-877-87.

Test Method for Dielectric Breakdown Voltage of Insulating Oils of Petroleum Origin Using VDE Electrodes, ASTM Std. D-1816-84.

Test Method for Flash Points by Cleveland Open Cup, ASTM Std. D-92-85.

Test Method for Inorganic Chlorides and Sulfates in Insulating Oils, ASTM Std. D-878-86.

Test Method for Interfacial Tension of Electrical Insulating Oils of Petroleum Origin Against Water by the Drop-Weight Method, ASTM Std. D-2285-85.

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Test Method for Oxidation Stability of Inhibited Mineral Insulating Oil by Rotating Bomb, ASTM Std. D-2112-86.

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Test Method for Saybolt Viscosity, ASTM Std. D-88-81.

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Appendix A - Sampling Procedures

The validity of the test results is dependent upon being certain that the oil sample is truly representative of the oil in the equipment. Thus, it is essential that the sample container of whatever type be free of contaminants, that the point of sampling within the equipment will produce a representative sample, and that sampling taps and connecting tubing be purged before the sample is taken.

Ordinarily, samples for physical tests can be taken in 1-L (1-qt) glass bottles, plastic containers with screw top, teflon-lined containers, or stainless steel cylinders. Glass bottles may either be cork or glass stoppered or fitted with screwcaps having cork or aluminum liners (inserts). Corks should be of good quality. DO NOT use rubber stoppers. Gas-in-oil samples may be taken in 150 - or 1,000-mL stainless steel cylinders (glass syringes and other samplers have been used by others). The 1,000-mL cylinders provide enough sample for both physical and gas-in-oil tests.

Steel containers, except teflon lined, should be rinsed in chlorothene or another comparable nonflammable solvent, dried, and washed in strong soapsuds. Then they should be thoroughly rinsed with water, dried in an oven at 105°C (220°F) for several hours, and removed from the oven. They should be corked while still warm. As the bottles cool, they should be sealed by dipping the necks in wax, then, the bottles should be stored for future use. These bottles should be opened only when the bottle temperature and the ambient temperature are the same or nearly so. The teflon-lined containers are easily cleaned in Stanisol and air dried.

Because of the importance of properly cleaned and treated containers, laboratory-approved containers should be used. Clean, dry, glass sample containers are available from most laboratories that perform the testing services. Oil samples in glass or other clear containers should be kept out of sunlight. Sunlight will break down materials in the oil and affect the test results.

A.1 Sampling Oil from Transformers and Circuit Breakers for Physical Tests. The following general sampling instructions should be followed.

(1) At least 2 L (2 qts) of oil should be taken as a sample for dielectric, acidity, and IFT tests. Allow space at the top of the container for expansion. If two 1-L (1-qt) bottles are used for a sample, label the bottles “1 of 2” and “2 of 2.”

(2) Samples from outdoor apparatus should be taken on clear days when the humidity is near normal and the oil is at least as warm or warmer than the surrounding air. Cold oil may condense enough moisture from a humid atmosphere to seriously affect its insulating properties and hot oil may absorb enough moisture from the air to give very inaccurate results when cooled to room temperature.

(3) Samples should never be drawn in rain or when the relative humidity of the atmosphere exceeds 70 percent.

(4) Guard against wind and dust.

(5) When taking samples from an opening, such as a valve, clean the valve thoroughly and allow enough liquid to run out (about 1 L (1 qt)) to remove any moisture or foreign material.

(6) In a sealed transformer, which has a vacuum, be sure to add nitrogen to a positive pressure before drawing the sample.

(7) Place the sample in the freezing compartment of a refrigerator overnight if possible. If the sample is cloudy when viewed the next day, it contains free water. Since free water is undesirable, take another sample to determine whether water is in the oil or was in the sample container.

A.2 Taking Oil Samples for Gas-In-Oil Analysis. This procedure has been developed to maintain uniformity of all oil samples taken in the field for a laboratory gas-in-oil analysis. Special stainless steel containers should be used for collecting samples of oil for gas-in-oil analysis using the gas chromatograph. These stainless steel containers are NOT to be used for any other purpose. Normally, the laboratory performing the required testing services cleans these containers to eliminate all contaminants and purges them with dry air for shipment to the field.

A.2.1 Preparation for Sampling.

(1) Obtain a can to catch overflow oil from the stainless steel container.

(2) Obtain two lengths of clear plastic tubing and attach one to each end of the stainless steel container. Make certain that the tubing between transformer and container is as short as possible.

A.2.2 Sampling Procedure. Modification of the transformer sampling valve may be necessary before a sample can be obtained (figure A.1).

(1) Connect the shortest enclosed plastic tube to valve #3 and fasten the connector sleeve for a tight seal. Do not connect to the cylinder.

(2) Open valve #3 and purge about 1 L (1 qt) of oil or until oil is clear and free of bubbles. Close valve #3.

(3) With the tube still full of oil, connect it to valve #2 on the cylinder.

(4) Connect the longer clear plastic tube to valve #1 on the cylinder.

(5) Hold the cylinder in a vertical position for filling. During filling, it should be tipped gently back and forth to vent any trapped bubbles. The assembly should be as shown in figure A.1.

(6) To fill the cylinder, open valves in the following order: 1, 2, and then 3.

(7) Allow at least 4 L (1 gal) of oil to flow through the cylinder before closing the valves. Close valves in the same order (i.e., 1, 2, and 3). This sample size may not be practical for all transformers.

(8) For disassembly:

    (a) Remove and drain tubing.

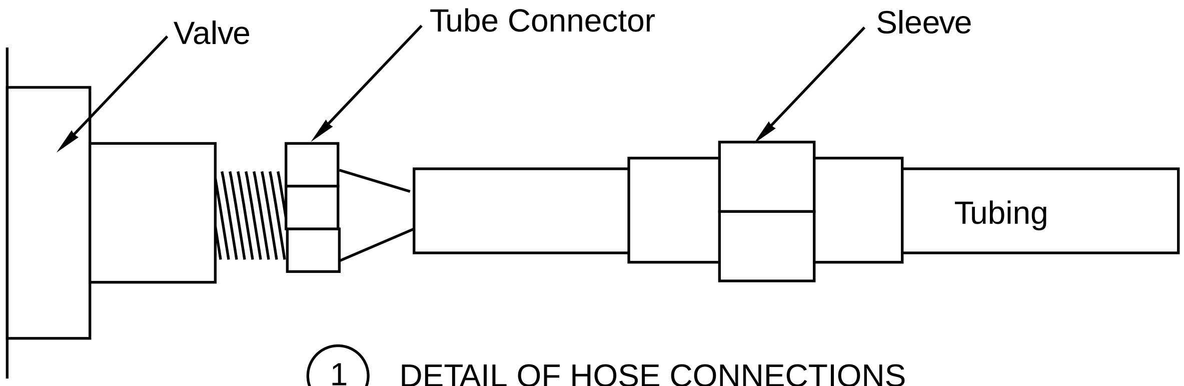
    (b) Pack cylinders and tubing in shipping box, as received.

    (c) Fill out data sheets for all samples and seal them in the oil proof plastic envelope.

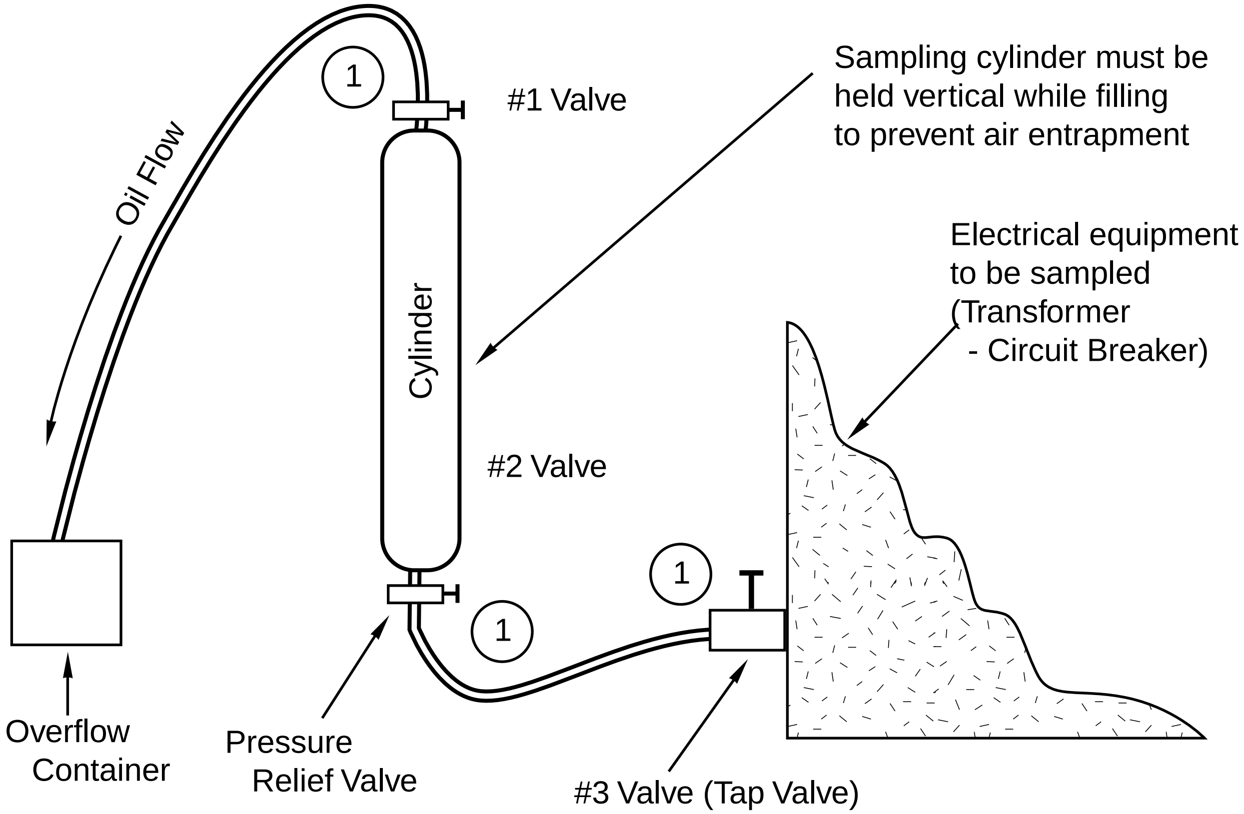
A.3 Taking Gas Samples for Gas Chromatograph Analysis. This procedure has been developed to maintain uniformity of all gas samples taken in the field while maintaining the principal objective of obtaining a representative sample that is free of all contaminants. Special stainless steel or glass cylinders are to be used for collecting samples of gas for use with the gas chromatograph. These containers are NOT to be used for any other purpose. If a laboratory performs the required testing, they normally clean the container to eliminate all contaminants.

Special care should be taken to avoid getting moisture in the sample since moisture can damage the analyzing equipment.

A.3.1 Sampling Procedure. If the gas system is under positive pressure, the following procedure applies; but, if the gas system is at atmospheric or negative pressure, refer to part II.



① DETAIL OF HOSE CONNECTIONS



OIL SAMPLING ARRANGEMENT

Figure A.1
Oil Sampling of Electrical Equipment

Source: Maintenance of Liquid Insulation, Bureau of Reclamation,
Power O and M Bulletin No. 11, July 1980.

Part I

(1) Attach a minimum length, approximately 152 mm (6 in), of clear plastic sample tubing to the transformer sampling valve.

(2) Open the transformer sampling valve and purge the plastic sampling tube for 15 seconds. Close the sampling valve.

(3) Connect the sampling cylinder, with both valves closed, while the plastic sampling tube is still exhausting.

(4) Open the valve on transformer end of sampling cylinder.

(5) Open the valve on outlet end of cylinder for 2 or 3 seconds. Close the valve off. Repeat this step five times.

(6) Close both valves on sampling cylinder (outlet end first, then transformer end). Close the transformer sampling valve and remove the sample cylinder and connecting tube.

(7) DO NOT wrap ANY kind of tape around valves or filling nozzles of sample cylinders.

(8) Identify samples. List air temperature at sampling time and approximate elevation.

Part II

This procedure should be followed if the gas sample is at atmospheric or negative pressure.

(1) Attach a minimum length, approximately 152 mm (6 in), of clear plastic sample tubing to the transformer sampling valve.

(2) With both valves closed, connect the sampling cylinder to the plastic sampling tube.

(3) The sample must be drawn with a vacuum pump or a hand aspirator bulb with a one-way valve connected to the outlet end of the container instead of the bladder.

(4) Open valve on outlet end of sampling cylinder while the vacuum pump (or hand aspirator) is in operation. With the sampling cylinder completely evacuated, close the valve on outlet end of sampling cylinder.

(5) Open transformer sampling valve for 2 or 3 seconds, then shut off. Repeat this step five times.

(6) Close valve on transformer end of sampling cylinder. With all valves closed, remove sample cylinder and connecting tubing.

(7) DO NOT wrap ANY kind of tape around valves or filling nozzles of the sample cylinders.

(8) Fill in tag attached to container and put container in shipping box.

A.4 Sampling Oil from Drums or Shipping Containers. The oil drum should remain undisturbed for several hours before drawing the sample.

(1) A glass or Pyrex thief is recommended for sampling, because it can be easily inspected for cleanliness. A glass tube approximately 910 mm (36 in) long, 25 mm (1 in) in diameter, and tapered at both ends is recommended for the sampling thief. A glass tube may also be used in place of the thief.

(2) The thief should be cleaned before and after sampling in the same manner as cleaning sample containers. When not being used, the thief should be corked at both ends.

(3) Discard the first full thief of oil.

(4) Draw the sample in the following manner.

  (a) With the top end covered with your thumb, lower the tube to within approximately one-eighth inch from the bottom of the drum.

  (b) Remove your thumb from the top opening until the thief is filled with oil.

  (c) Replace thumb over top of thief and remove thief full of oil to the sample container. Release thumb to permit oil to run into the container.

A.5 Shipping. The shipping of the samples for testing should be sent in accordance with requirements specified by the testing laboratory.

Appendix B - Dielectric Test: Equipment and Methods

B.1 General. Since dissolved water cannot be detected by dielectric test, and the dissolved water emulsifies out at lower temperatures, the temperature of the oil for testing should be nearly the same for each test in order to obtain consistent results. The temperature range for testing the oil should be between 20 and 30°C (68 and 86°F). Dielectric tests should be conducted in accordance with ASTM D-877-87 for power circuit breakers and ASTM D-1816-84 for power transformers. For convenience, these standards (as applicable to Western) are presented below. Figure B.1 is an example of a test setup.

B.2 Dielectric Test. ASTM D-877-87 (Disk Electrodes).

B.2.1 Scope. This method of testing electrical insulating oils applies to oil of petroleum origin for use in cables, transformers, oil circuit breakers, and similar apparatus as an insulating or cooling medium, or both.

B.2.2 Apparatus (Manual Tester). Portable oil dielectric testers are usually used for making dielectric tests on oil in the field. Units with a variable high voltage of 40 kV or greater between the electrodes and which have Bakelite or other approved material test cups are considered satisfactory. The following instructions cover the adjustment and care of the electrodes and test cup.

(1) The electrodes and the test cup shall be wiped clean with dry, calendered tissue paper or with a clean, dry chamois. The spacing of the electrodes shall be checked with a standard round gauge having a diameter of 2.54 mm (0.100 in) or with flat steel “go” and “no go” gauges having thicknesses of 2.53 and 2.55 mm (0.0995 and 0.1005 in) respectively; the electrodes shall be locked in position. It is important to avoid touching the electrodes or the cleaned gauge with fingers or with portions of the tissue paper or chamois that have been in contact with the hands.

The electrodes and the test cup shall be rinsed with Stoddard solvent or chlorothene until they are entirely clean. To avoid any possible contamination, care shall be taken to avoid touching the electrodes or the inside of the cup after cleaning.

After a thorough cleaning, the test cup shall be filled with a sample of the cleaning fluid, voltage shall be applied and uniformly increased at a rate of approximately 3 kV/s (rms value) until breakdown occurs. If the breakdown is not less than the established value of the oil being tested, the test cup shall be considered in suitable condition for testing. If a lower value is obtained, the cup shall again be thoroughly cleaned and the test repeated. A cleaning fluid whose breakdown is not less than the established value of the oil being tested must be used.

(2) At the beginning of each day’s testing, the electrodes shall be examined for pitting and carbon accumulation, and the electrode spacing shall be checked. The test cup shall be thoroughly cleaned and tested as described in subparagraph B.2.2 (1). It shall then be flushed with a portion of the sample to be tested before it is filled for the test.

(3) If the test of a sample is below the breakdown value being used by the operator as a minimum satisfactory value, the cup shall be cleaned and prepared as described in subparagraph B.2.2 (1) before testing the next sample.

NOTE: Evaporation of the cleaning fluid from the electrodes may chill them sufficiently to cause moisture to condense on their surfaces. For this reason, after the final rinsing with cleaning fluid, the cup must immediately be flushed with the oil to be tested and then filled for the test.

B.2.3 Procedure.

(1) Preparation of Sample. The dielectric strength of liquid dielectrics may be markedly altered by the migration of impurities through the liquid. In order that representative test specimens may be obtained, the sample container shall be gently tilted or inverted and the oil swirled several times before each filling of the test cup, in such a way that any impurities present will be thoroughly mixed with the dielectric. Rapid agitation is undesirable, since it introduces an excessive amount of air into the liquid. Immediately

Figure B.1
A Hipotronics Dielectric Test Setup

Courtesy of Sierra Nevada Region.

after agitating, the test cup shall be filled with oil to a height of not less than 20 mm (0.787 in) above the top of the electrodes. In order to permit the escape of entrapped air, the container shall be gently rocked a few times and the oil allowed to stand in the cup for 3 minutes before voltage is applied.

NOTE: It is impracticable to handle oils having viscosities ranging between 60 and 100 Sus at 99°C (210°F) according to the procedure in section B.2.3 (1). When testing high-viscosity oils in this range, the sample should be allowed to stand until it reaches room temperature, which should not be less than 20°C (68°F). The sample container should not be tilted or swirled as prescribed in section B.2.3 (1), and it should be opened only when the sample is ready for testing.

(2) Test Temperature. The temperature of the sample when tested shall be the same as that of the room, but shall not be less than 20°C (68°F). Testing of oil at a temperature lower than that of the room is likely to give variable results which may be misleading.

(3) Application of Voltage. Voltage shall be applied and increased at a uniform rate of 3 kV/s from zero until breakdown occurs as indicated by a continuous discharge across the gap. Occasional momentary discharges which do not result in a permanent arc may occur; they should be disregarded.

B.2.4 Number of Tests.

(1) Reference Testing. When it is desired to determine the dielectric breakdown voltage of a new liquid for reference purposes, one breakdown shall be made on each of five successive fillings of the test cup. The breakdown voltage thus obtained shall be subjected to the criterion for statistical consistency as specified in section B.2.4 (4). If the five values meet this criterion, their average shall be reported as the dielectric breakdown voltage of the sample. If they do not meet this criterion, one breakdown on each of five additional cup fillings shall be made, and the average of the 10 breakdowns shall be reported as the dielectric breakdown voltage of the sample. No breakdown shall be discarded.

(2) Routine Testing. When it is desired to determine the dielectric breakdown voltage of a liquid on a routine basis, one breakdown may be made on each of two fillings of the test cup. If no value is below the specified acceptance value, the oil may be considered satisfactory, and no further tests shall be required. If either of the values is less than the specified value, a breakdown shall be made on each of three additional cup fillings, and the test results analyzed in accordance with section B.2.4 (1).

(3) Routine Testing (Alternative Method). When it is desired to determine the dielectric breakdown voltage of a liquid on a routine basis, five breakdowns may be made on one cup filling with 1-minute intervals between breakdowns. The average of the five breakdowns shall be considered the dielectric breakdown voltage of the sample provided the breakdown values meet the criterion for statistical consistency as specified in section B.2.4 (4). If the breakdown voltages do not meet this criterion, the contents of the cup shall be discarded, the sample container again gently inverted and swirled, the cup again filled, and five breakdowns made on this second cup filling. The average of the 10 breakdowns shall be considered as the dielectric breakdown voltage of the sample. No breakdown shall be discarded.

(4) Criterion for Statistical Consistency. Compute the range of the five breakdowns (maximum breakdown voltage minus minimum breakdown voltage), and multiply this range by three. If the value obtained is greater than the next to the lowest breakdown voltage, it is probable that the standard deviation of the five breakdowns is excessive, and therefore the probable error of their average is also excessive.

B.2.5 Report. The report shall include the following:

- The procedure used,
- The voltage (rms value) at each breakdown and the average of all of the breakdowns (5 to 10). All results shall be reported to the nearest kilovolt, and
- The approximate temperature of the oil at the time of the test.

B.3 Dielectric Test. ASTM D-1816-84 (VDE Electrode). The present ASTM D-877-87 gap consists of a 25.4 mm (1 in) diameter disk, square-edged electrodes spaced at 2.54 mm (0.1 in). Use of this test gap results in a uniform electrostatic field at the centerline of the test disks, and a highly nonuniform field at the edges of the disks. To attain a uniform field strength at all points, spherical electrodes would have to be used. Between these extremes of a highly distorted field and an ideal uniform field, a third gap configuration, designated as VDE or ASTM D-1816-84, has been used. The VDE gap specifications call for a sector diameter of 36 mm (1.4 in) and a 25-mm (1-in) radius of curvature for the spherically capped electrodes. A gap of about 2 mm (0.08 in) between electrodes has been found to give about the same breakdown voltage relationships in the 25- to 30-kV range as the ASTM D-877-87 configuration. Tests have shown that:

- The VDE configuration depicts more accurately the average electric strength and scatter of the oil as the transformer sees it,
- The VDE gap is relatively sensitive to oil quality; the ASTM D-877-87 gap is less sensitive, and
- Point electrodes are almost completely insensitive to oil quality.

The VDE cell, in which a quart of oil is tested between VDE electrodes, while being mildly circulated, realistically measures changes in oil strength which determine the electrical strength of typical transformer construction. This test method (ASTM D-1816-84) is presently used only as a laboratory test and research tool by industry.

Appendix C - Oil Acidity Test: Equipment and Methods

The acid number (commonly called neutralization number) is the mass of KOH in milligrams required to neutralize the acids in 1 g of oil; for example, 0.3 mg of KOH/g of oil.

With a commercial test kit (figure C.1), the oil sample, instead of being weighed, is more conveniently poured into a graduated glass cylinder. Single doses of KOH are furnished in sealed ampules and the dosage is indicated by the number imprinted on the ampule. With the glass cylinder filled with oil to the level marked 10, and a No. 1 ampule added, a mixture is obtained which equals 0.1 mg of KOH/g of oil; a No. 3 ampule added equals 0.3 mg of KOH/g; a No. 6 ampule added equals 0.6 mg of KOH/g; and a No. 15 ampule added equals 1.5 mg of KOH/g of oil.

The neutral solution is to be put into the measured sample before adding the KOH. This solution “washes” the oil, and the KOH can then act on the acids more readily. The neutral solution contains a color-changing indicator. If any KOH is left after the acids are neutralized, the indicator is pink; but if the KOH is all used up, the indicator is colorless like water.

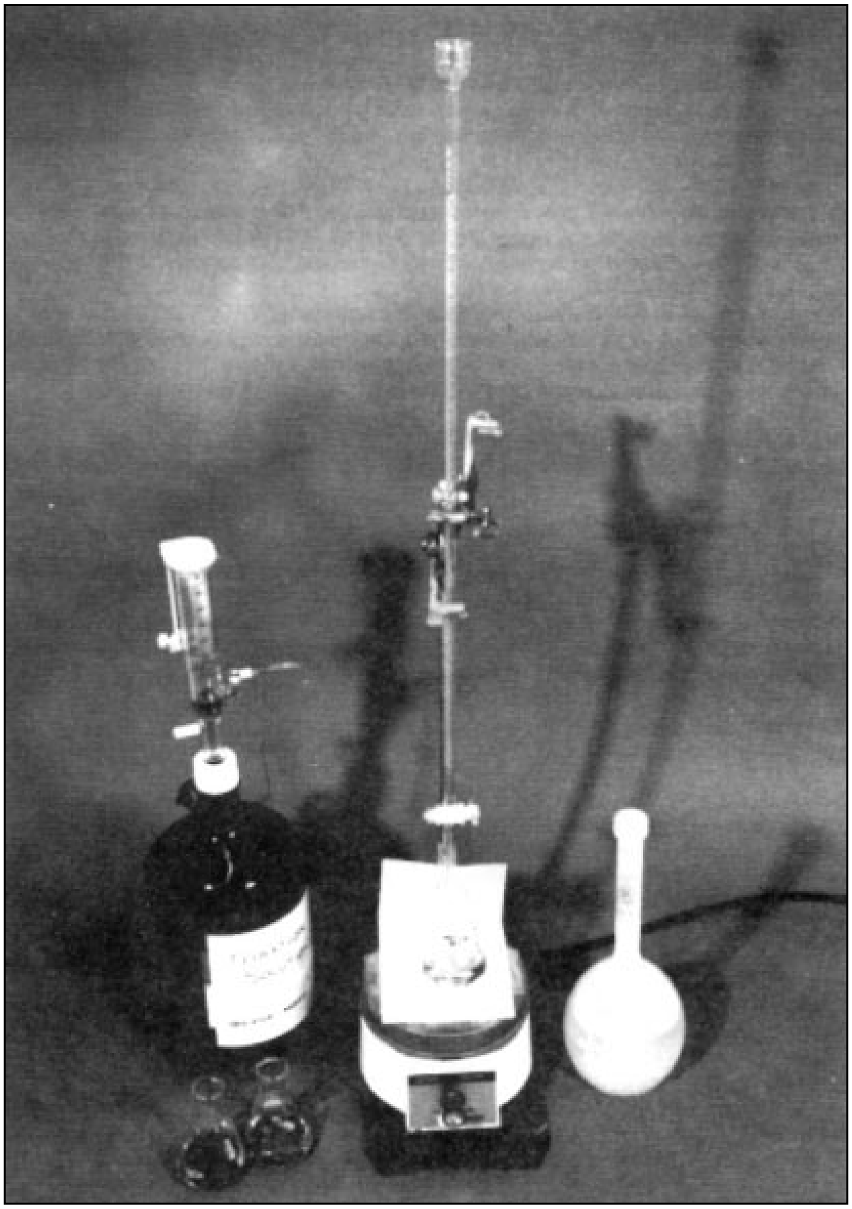


Figure C.1
A Commercial Test Kit With Titration Solution,
Three Glass Mixing Cylinders, and a KOH Solution.

Courtesy of Sierra Nevada Region

Appendix D - Interfacial Tension (IFT) Test: Equipment and Methods for Field Use

D.1 The IFT Test of Oil by the Drop-Weight Method (ASTM D-2285-85).

D.1.1 Scope. This method describes a comparatively rapid procedure more applicable to field use than laboratory use, for measuring, under nonequilibrium conditions, the IFT of electrical insulating oils of petroleum origin against water.

D.1.2 Summary of Method. The IFT is determined by measuring the volume of a drop of water that the oil will support. The larger the drop of water, the higher the IFT of the oil. The instrument used to measure the volume of the drop of water is calibrated in newtons per meter to indicate the approximate IFT.

This method is based on the use of PTA (Professional Technical Associates) (P.O. Box 123, Signal Mountain, Tenn.) tensiometers, model V1a or V2. Other equivalent-type tensiometers may be used with appropriate modifications in procedure. Examples are the Fisher Surface tensiometer (figure D.1) and CSC-DuNovy tensiometer which are used for acceptance purposes (ASTM D-971-82 and ASTM D-1331-89).

D.2 Detailed Explanation of PTA Model 6 Tensiometer.

D.2.1 Apparatus. The PTA model 6 interfacial tensiometer (figure D.2) has been accepted by ASTM as a suitable substitute for the models V1a and V2. The primary features have been preserved; no changes in the method used in ASTM D-2285-85 are involved.

The model 6 features an almost unbreakable dial (figure D.3) made of poly-carbonate (Lexan). The dial has 50 calibrations and two number scales. Each small calibration line represents 0.001 N/m (1 dyn/cm) therefore, with the double scale, each number represents 60.01 N/m (10 dyn/cm) and should be considered as 0.01, 0.02, 0.03, etc. Values from 0 to 0.0499 N/m (0 to 49.9 dyn/cm) are read from the lower scale. Values from 0.05 to 0.0999 N/m (50 to 99.9 dyn/cm) are read on the upper scale.

The vacuum base permits the tensiometer to firmly grip any smooth surface. The tensiometer is extremely stable and is lightweight; it weighs 850 g (30 ounces).

The orifices of the model 6 have the same dimensions as previous models but are machined with a Luerlock (figure D.4) which permits easy filling of the barrel; a spare orifice is provided; and a syringe, (B) in figure D.2 provides for easy filling of the tensiometer barrel.

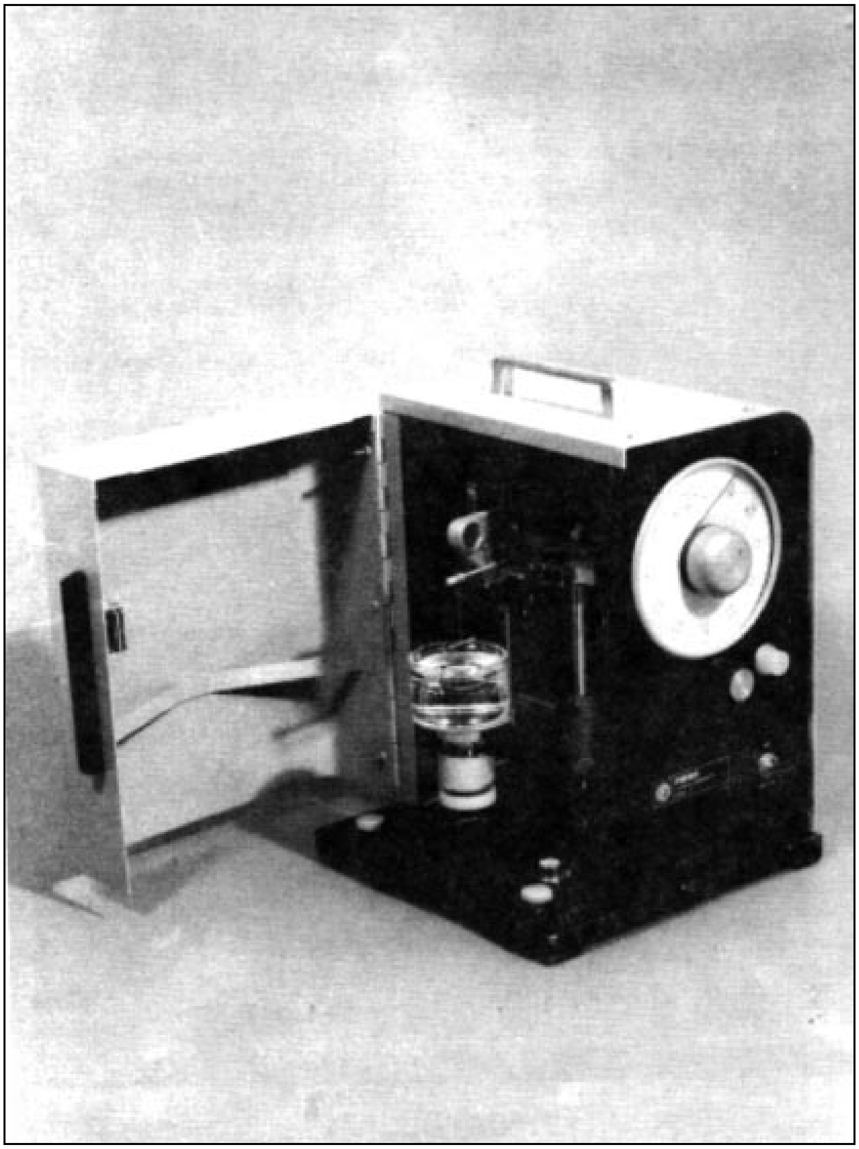


Figure D.1
A Fisher Surface Tensiometer.

Courtesy of Sierra Nevada Region.

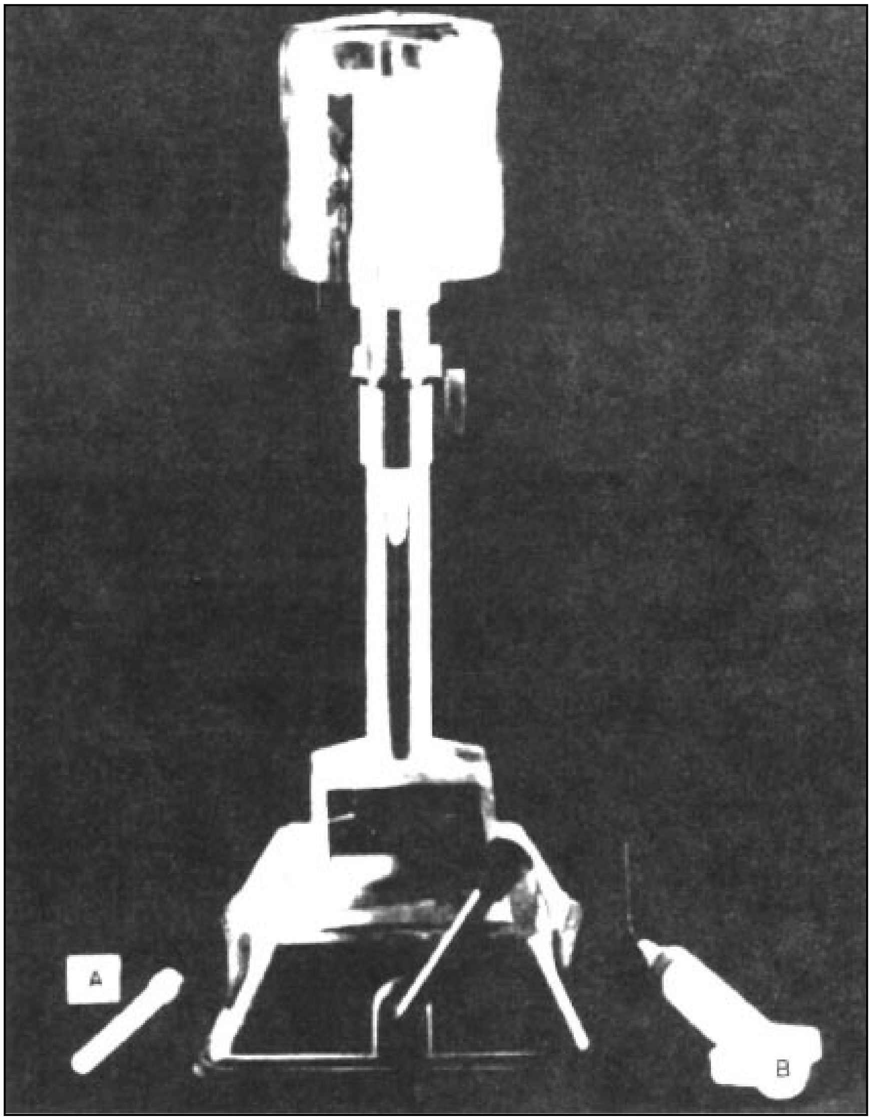


Figure D.2
The Model 6 PTA Interfacial Tensiometer
Mounted in Support Stand.

The tubing orifice cover (A) is shown on the left side of the support stand. The cover should be placed over the orifice needle when the instrument is not in use. The syringe (B) with bent needle is used for filling the tensiometer barrel.

Source: Bureau of Reclamation, Bulletin No. 11, Photo P801-D-74917, July 1990.

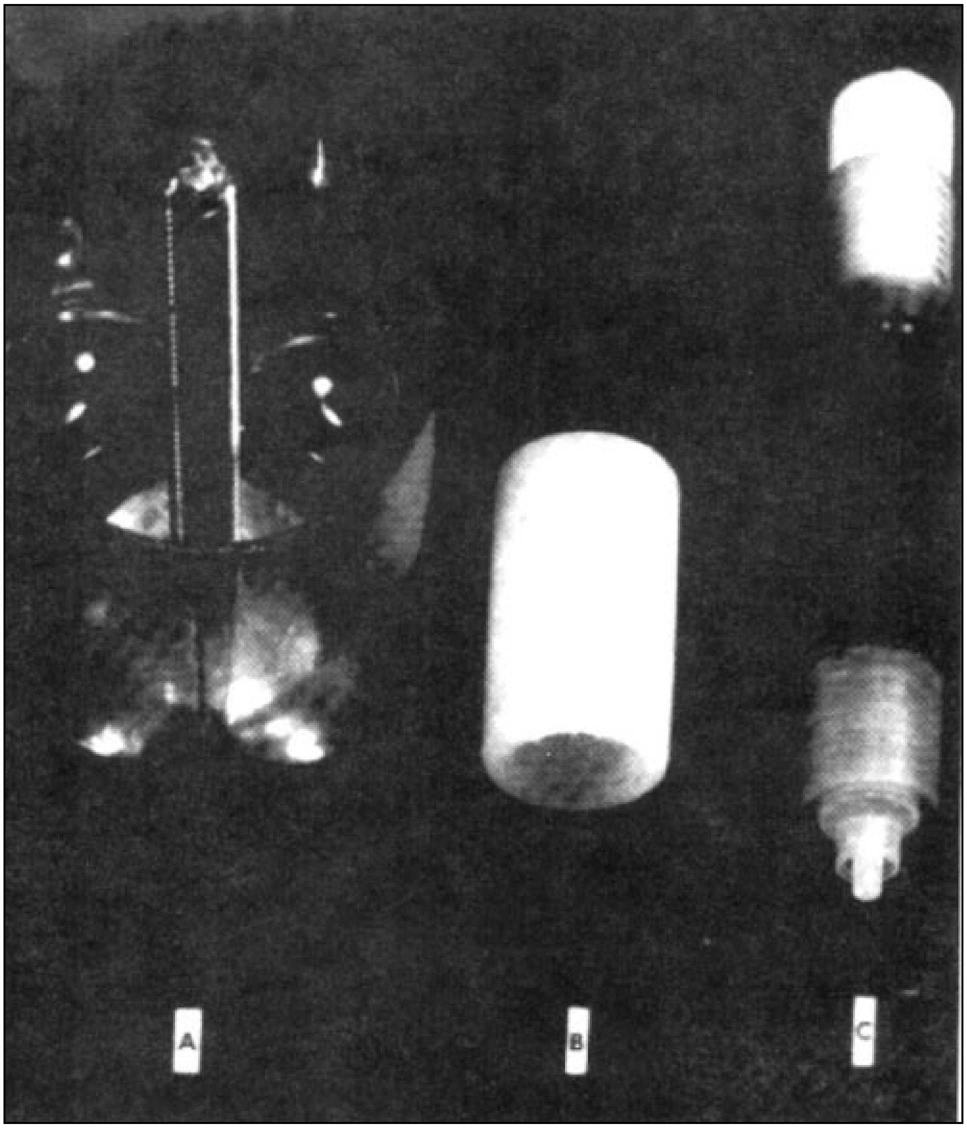


Figure D.3
Dismantled Tensiometer.

(A) Polycarbonate (Lexan) dial with micrometer screw attached. (B) Teflon lead nut.
(C) Tensiometer barrel with white Teflon plug.

Source: Bureau of Reclamation, Bulletin No. 11, Photo P801-D-74918, July 1990.

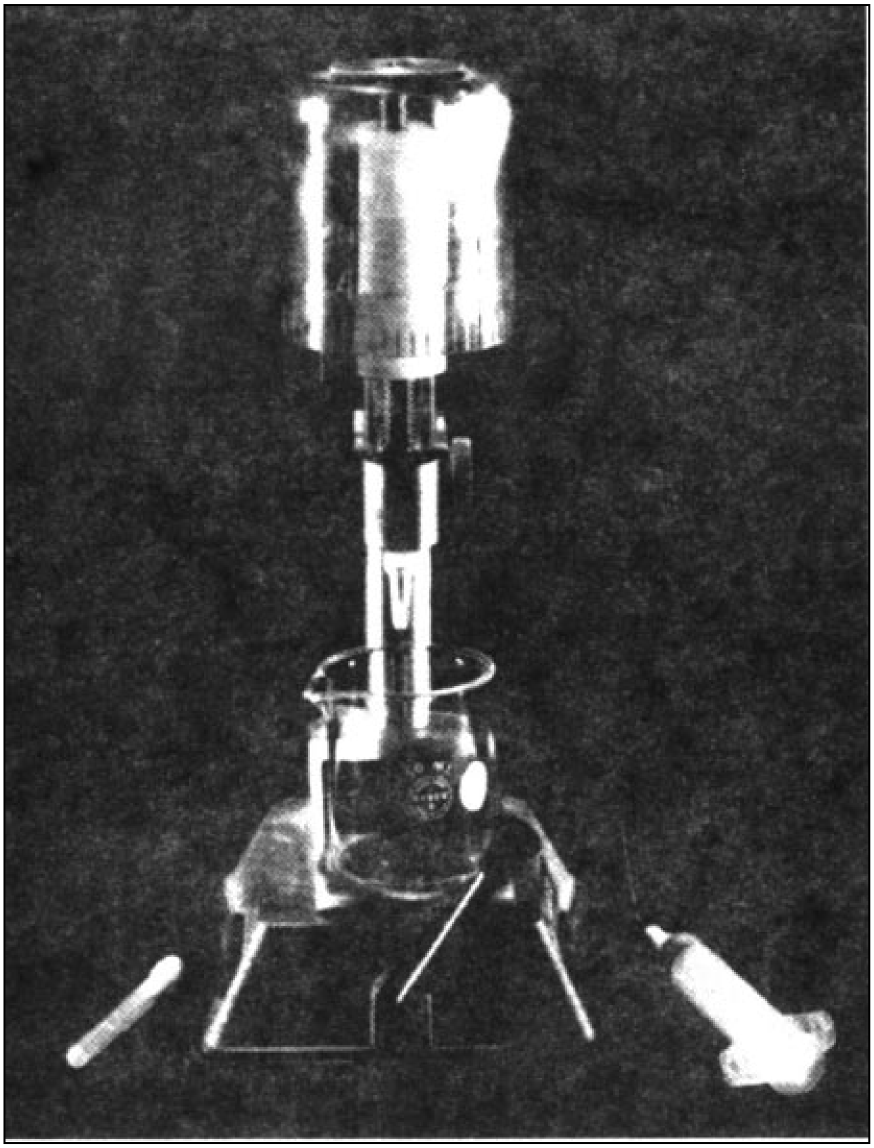


Figure D.4
Tensiometer With 50-mL Beaker Under the Tubing Orifice.

Handle in front operates the section base. Orifice with Luerlock is attached to bottom of barrel and extends into beaker.

Source: Bureau of Reclamation, Bulletin No. 11, Photo P801-D-74919, July 1990.

D.2.2 Operation Problems and Solutions. Prior to using the tensiometer for the first time, dismantle the instrument as shown in figure D.3. Be certain that the white Teflon nut on the top of the barrel, (C) of figure D.3 is screwed tightly into the barrel. Check the top of the nut for sufficient Vaseline for sealing. If Vaseline is present, reassemble the unit, if not, add sufficient Vaseline to form a good seal when (B) and (C) are fastened tightly together.

- Problems and Corrective Measures to be Taken -

  Water dripping from orifice. - Check Vaseline seal (between Teflon plug and lead nut).

  Micrometer screw turns but will not advance. - Dismantle tensiometer and tighten packing nut (B) and white Teflon nut on top of tensiometer barrel (C).

  Excessive deviations in scale readings during calibration. Check orifice for dirt and lint; check Vaseline seal.

D.2.3 Filling Tensiometer Barrel with Water. The orifice (A) and pointer (B) (figure D.5) are removed, the micrometer screw is backed out to maximum position, the tensiometer is inverted, and the barrel is filled to overflowing with approximately 25°C (77°F) distilled water using the filler syringe which has a bent needle for this purpose. At this point, inspect the interior of the barrel for air bubbles. (It is rare that no bubbles are present.) To remove these small air bubbles:

> Push the plunger of the filler syringe into the syringe barrel as far as it will go. Place the tensiometer in the inverted position, insert the needle of the filler syringe into the tensiometer barrel, then using the plunger of the syringe, remove about 5 to 10 percent of the water. Place the tensiometer in a horizontal position and by tilting the tensiometer barrel, pick up the small air bubbles by passing the large air bubble (formed by removing the water from the barrel) over the small bubbles. Place the tensiometer in the inverted position. Fill the filler syringe with water and expel air bubbles. Place the end of the bent needle of the filler syringe under the surface of the water in the tensiometer and fill the tensiometer to overflowing and withdraw needle.

Attach pointer and orifice, (A) and (B) of figure D.5. Turn dial until nothing but water is expelled from the orifice. The tensiometer should now be free of air. Place in holder.

D.2.4 Calibration of Tensiometer. The tensiometer full of distilled water at 25°C (77°F) and void of air is placed in the mounting stand (figure D.2). The 50 mL beaker containing at least one-half inch of distilled water is placed on the beaker platform of the mounting stand. The tensiometer is lowered until the tip of the orifice is within 6.4 mm (0.25 in) of the surface of the water (figure D.4).

The temperature of the water in the orifice may differ from that of the water in the tensiometer; therefore, replace the water in the orifice by turning the dial clockwise until five drops of water have been expelled. Stop all movement of the dial immediately as the last drop leaves the orifice tip.

Record the reading on the scale, then expel a single drop of water and record scale reading. Second reading minus first reading equals the volume, in terms of divisions on the scale, of a drop of water expelled in air.

The average of 10 such “drops in air” is taken as the orifice calibration water in air.

Any reading deviating as much as 0.20 from the average is discarded, and if any reading is as much as 0.40 from the average, the whole series is discarded and the cause of such deviation determined. Leakage of air is the usual source of variation, with dirt and lint on the orifice also a possible cause.

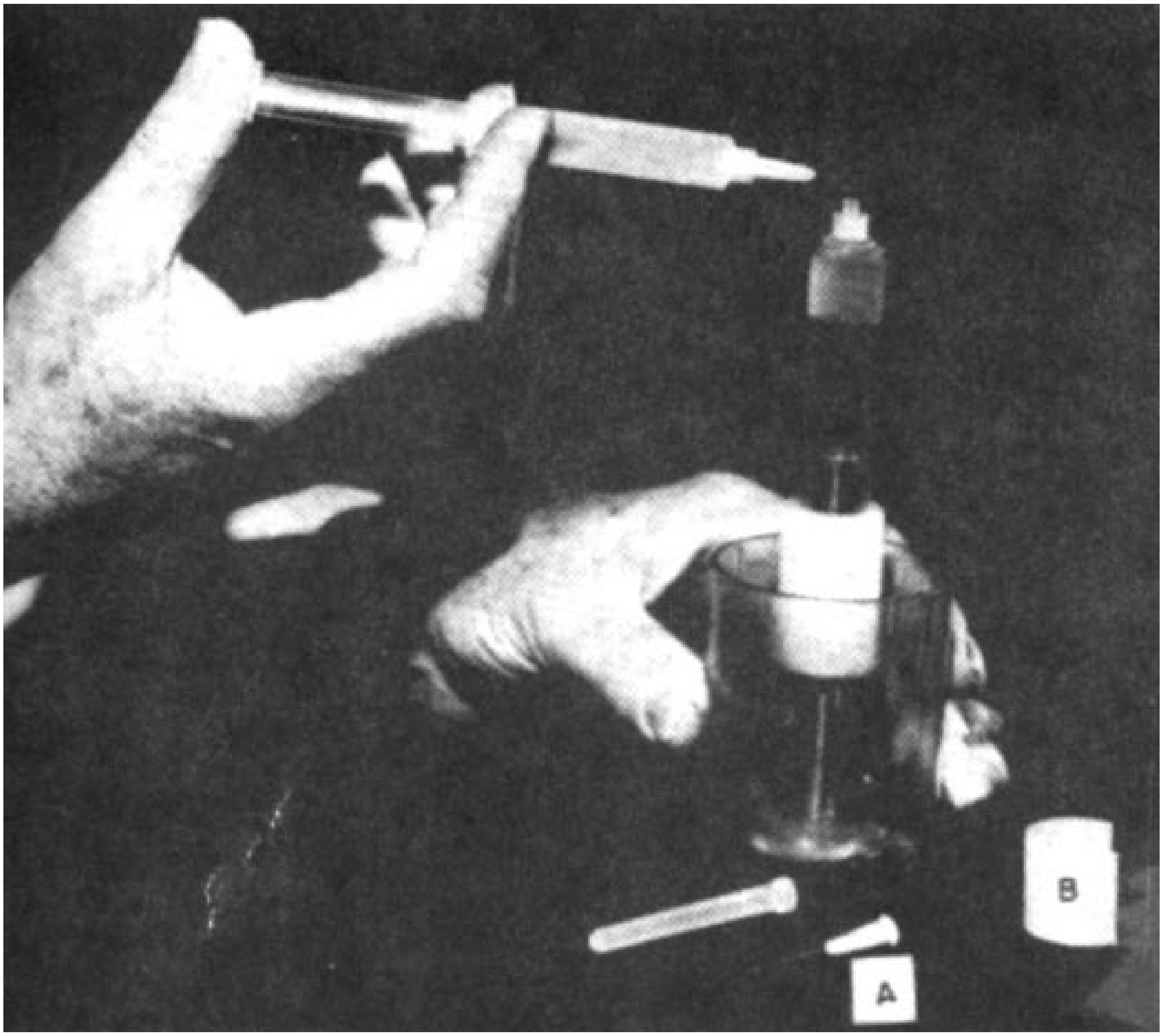


Figure D.5
Technique for Filling Tensiometer Barrel With Distilled Water.

Source: Bureau of Reclamation, Bulletin No. 11, Photo P801-D-74920, July 1990.

The calibration drop should be checked once each day that the tensiometer is to be used in order to assure accurate results. The calibration drop should be determined prior to starting the day's testing program because the calibration procedure not only obtains the drop volume, in terms of divisions on the scale, but also is an indicator as to the performance of the instrument. An instrument that is not functioning properly will not produce drops within the following specification limits of the test procedure. An example of determining the calibration drop follows:

A = Dial reading before expelling drop.
B = Dial reading after expelling drop.
C = B - A (Scale divisions per drop of water in air.
Average of 10 drops equals the calibration of tensiometer.)

	B	**-**	**A**	**=**	**C**
1.	40.0	-	31.2	=	8.8
2.	49.0	-	40.0	=	9.0
3.	58.2	-	49.0	=	9.2
4.	67.1	-	58.2	=	8.9
5.	76.1	-	67.1	=	9.0
6.	85.3	-	76.1	=	9.2
7.	94.5	-	85.3	=	9.2
8.	53.6	-	44.5	=	9.1
9.	62.8	-	53.6	=	9.2
10.	71.8	-	62.8	=	9.0
					90.6

Dividing the total by 10 (the number of drops), the resulting number (9.06) represents the average of the 10 readings which is the calibration value of the tensiometer. Subtracting reading No. 1 (8.8) from the average (9.06) the difference (0.26) is greater than the specified 0.20 and the 8.8 reading should be discarded. Another drop was measured and the value of this drop (9.1) replaced the 8.8 drop. The final total for 10 drops was 90.9, raising the new calibration value from 9.06 to 9.09.

- Important instruction. Review the tensiometer settings from the above example for drops 7 and 8. It is evident that the A and B settings for drop 7 are a continuation of the settings of preceding drops; however, the A and B settings for drop 8 are decidedly different.

  Tensiometer readings under 100 divisions are desirable. It was evident that an additional nine divisions added to the B setting (94.5 divisions) for drop 7 would give a value of 103.5 divisions. An examination of the tensiometer will show that 94.5 on the upper scale of the dial corresponds to 44.5 on the lower scale. This is the technique used in order to avoid tensiometer readings in excess of 100 divisions. Reviewing the data listed above, it will be noted that values for drops 1 and 2 were taken from the lower scale, whereas, for drops 3, 4, 5, 6, and 7 the upper scale was used. The value for 8A was taken from the lower scale, the remaining values 8B through 10B were from the upper scale.

D.2.5 Apparatus Preparation Prior to Testing Oil Samples. Place the tensiometer with orifice attached (the unit should be full of water and free of air bubbles) in the holder. Wipe the tensiometer tubing orifice free of oil with clean lint-free paper, avoiding any upward motion which may embed a bit of fiber on the sharp orifice.

CAUTION: Do not use an oil solvent on the orifice or barrel.

Force a few drops of water through the orifice by turning the polycarbonate dial (figure D.3). This will clean the orifice. Contamination in the barrel or orifice can be removed by dismantling the tensiometer and flushing the parts with distilled water. Do not use detergents to clean the barrel. Dry thoroughly and reassemble. Be sure to replace the Vaseline seal.

Clean the sample container (beaker) removing any residual oil by flushing with Chlorothene. (Benzene or petroleum naphtha can be used, however, they are flammable.) Allow solvent to evaporate, then wash in detergent, and rinse thoroughly in cold tap water followed by distilled water. Place beakers in an inverted position over a clean dry towel.

D.2.6 Test Procedure. Apparatus, sample, and distilled water should be at a preferred common temperature of 25°C (77°F) plus or minus 1°C (1.8°F). Absolute control at this temperature usually is not possible in the field; however, test as close to this temperature as possible. Definitely avoid large temperature changes particularly when testing comparison samples taken at specified time intervals.

This method is a comparatively rapid procedure particularly applicable for field use. Therefore, filtration adds an undesirable extra step. Also, it is anticipated that oil samples drawn from electrical equipment in the field will not contain heavy oil sludge, such as may be found in samples taken at the end of laboratory oxidation tests, which would interfere with the determination of IFT.

(1) Replace the 50-mL beaker used to establish the volume of the calibration drop with a beaker of the same capacity. Pour the unfiltered oil sample into this beaker to a depth of at least 25.4 mm (1 in). Place beaker containing oil sample on the tensiometer table, lower tensiometer until the orifice tip is immersed about 12.7 mm (0.5 in) into the oil.

(2) Record the dial reading. Expel one drop of water. Record the dial reading. Subtract the first reading from the second reading and record the difference (volume).

(3) Expel about three fourths of the volume of water found in the paragraph above and allow this drop to age for 30 seconds.

(4) Expel, slowly, enough water to cause the drop to fall so that the total time is between 45 and 60 seconds.

(5) Note the volume of water in the drop in terms of divisions on the scale. This reading gives the IFT of an oil of average density.

Example:

Scale reading before expelling drop of water = 40.0 divisions

Scale reading after expelling drop of water = 86.6 divisions

Volume of water in drop, 86.6 - 40.0 = 46.6 divisions

Approximately three-fourths of 46.6 = 35.0 divisions

The scale reading after expelling the trial drop was 86.6 divisions on the upper scale. This corresponds to 36.6 divisions on the lower scale. Add 35 divisions (approximately 3/4 of the volume of the trial drop) to the scale reading (36.6 divisions). Turn dial to 71.6 and allow drop to age 30 seconds. Then turn dial slowly until drop of water falls into oil. The total elapsed time from the time the drop starts to form on the orifice tip until it drops from the tip should not exceed 60 seconds.

Scale setting at 60 seconds = 83.0 divisions

Minus scale setting at 0 seconds = 36.6 divisions

Equals volume of water in drop = 46.4 divisions

Volume x 0.001 equals IFT of the oil = 0.0464 N/m

If more accurate test results are desired or if the field IFT of an oil is 0.02 N/m (20 dyn/cm) or less, a sample of the oil should be sent to the laboratory for a more accurate and detailed analysis.

Appendix E - Doble Tests of Liquid Insulation With MH and M2H Test Sets

E.1 General. In order that samples of liquid insulation may be tested with the Doble Engineering Company test sets, a special cell has been constructed which is essentially a capacitor utilizing oil as the dielectric. Provided with the cell is a container in which the cell may be housed and carried when not in use. Figure E.1 shows the cell and the metal carrying pail.

The cell holds approximately 1 L (1 qt) and should be filled until there is about 19.0 mm (0.75 in) of liquid above the top of the cylinder inside the cell. The cell should be set on a reasonably level base so that the surface of the liquid will be approximately level. The cover should be properly seated.

The test connections are made as shown in figure E.2. The hook of the high-voltage cable should be connected to the handle on the cover. The high voltage guard ring on the cable pothead should be connected to the guard ring of the cell which is fastened to the cover. The outer cylinder should be connected to the ungrounded specimen tester (UST). A clearance of at least 25.4 mm (1 in) should be maintained between the cable hook and the cell guard ring so that flashover will not occur between these parts.

The test voltage should be gradually raised to 10 kV. As the spacing between the plates of the cell is about 4.8 mm (3/16 in), the sample should not break down at these voltages unless it is in very poor condition. Meter readings should be taken and the power factor calculated.

When drawing a sample of liquid insulation from a transformer or circuit breaker, care should be taken to obtain a representative sample. Let sufficient liquid drain through the pipe and valve so that any dirt or water lodged in the pipe will be drained before filling the test cell.

Air bubbles, water, and other foreign material are the usual cause of breakdown in the cell. If the sample is allowed to stand in the cell for a short time before the test is made, the entrapped air will have a chance to work out and foreign particles to settle to the bottom. If there is an insufficient amount of liquid in the cell, sparkover will take place above the liquid level.

Immediately after the sample has been tested, its temperature should be taken while still in the cell. The power factor should then be corrected to 20°C (68°F) using the multipliers in the column headed “Oil and Oil-Filled Power Transformers” in the table titled “Table of Multipliers for Use in Converting Power Factors at Test Temperatures to Power Factors at 20°C” in the Doble Manual titled “Type M2H Instruction Manual, Electrical Insulation Testing”.

Obviously, the test cell should be cleaned thoroughly every time a different sample is tested. Generally speaking, so long as the same type of liquid is to be tested, the cell is cleaned adequately by washing it with a good, new sample or a portion of the sample to be tested. It is better not to wipe out the container with rags, as cotton fibers, etc., may be left in the cell and consequently may affect the breakdown voltage of the sample.

When transporting the cell, it should be packed carefully to prevent damage. The packing in which the cell is shipped may be utilized for this purpose.

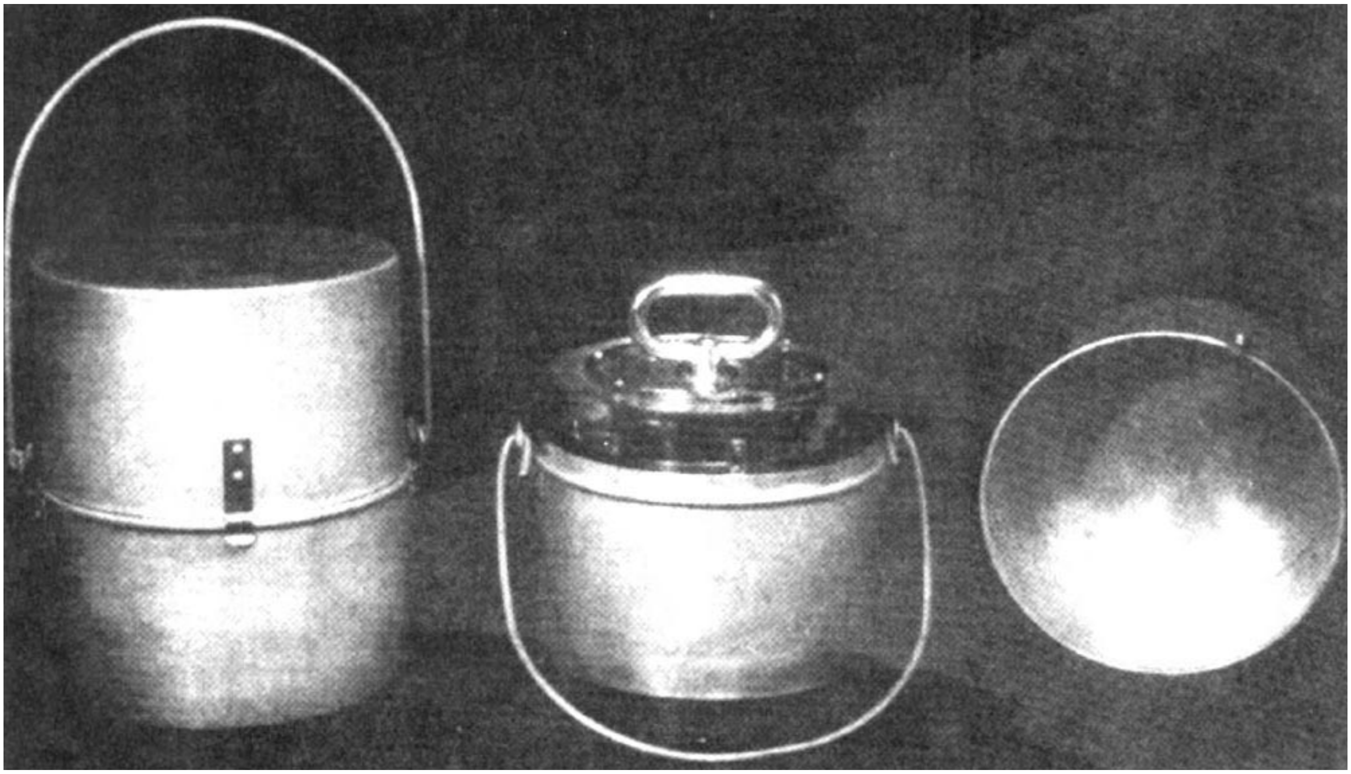


Figure E.1
Liquid-Insulation Cell With Metal Carrying Pail.

Source: Maintenance of Liquid Insulation, Bureau of Reclamation,
Power O and M Bulletin No. 11, July 1980.

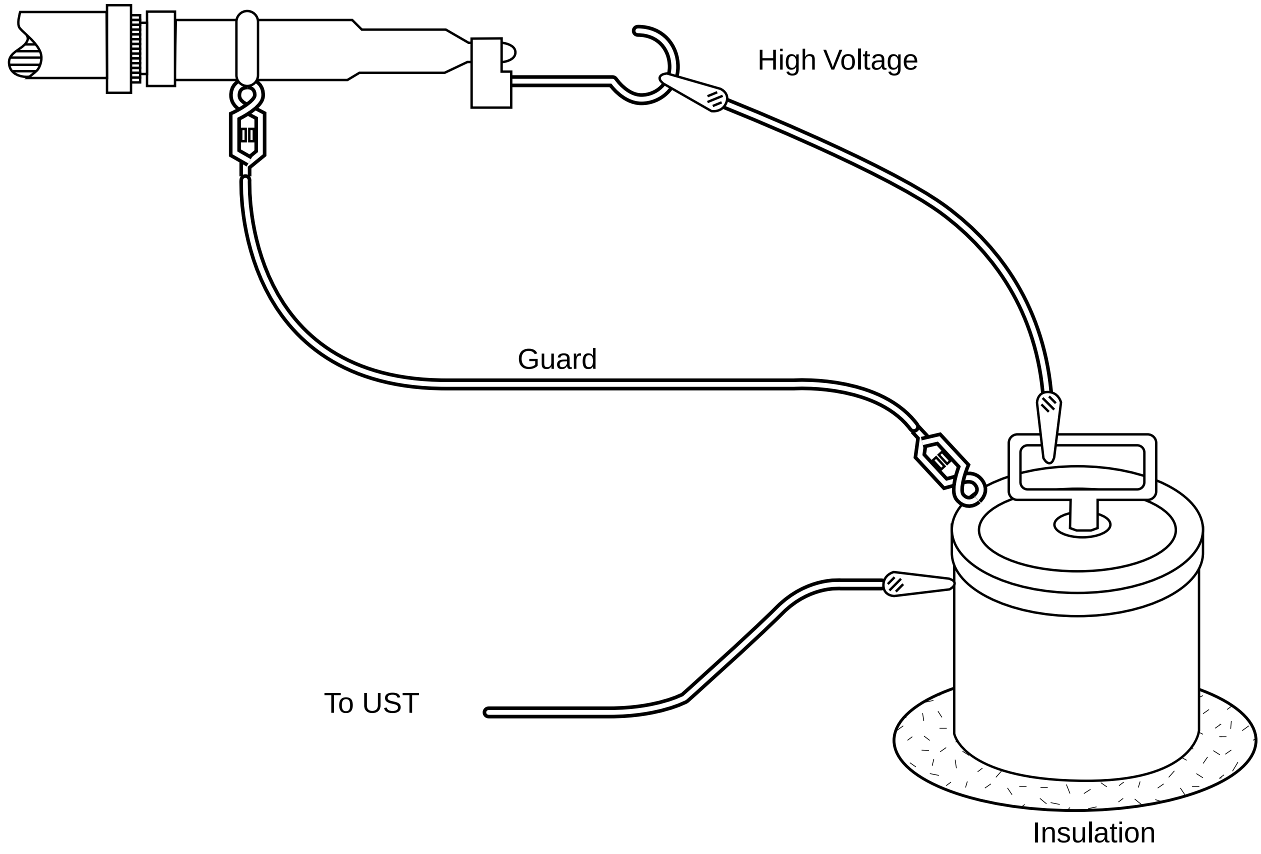


Figure E.2
Liquid-Insulation Cell Connected for Testing.

Source: Maintenance of Liquid Insulation, Bureau of Reclamation, Power O and M Bulletin No. 11, July 1980.

E.2 Oil. Good, new oil has a power factor of 0.05 percent or less at 20°C. Higher power factors indicate deterioration or contamination with moisture, carbon or other conducting matter, varnish, Glyptal, sodium soaps, asphalt compounds, or deterioration products. Carbon or asphalt in oil can cause discoloration. Carbon in oil will not necessarily increase the power factor of the oil unless moisture is also present. It is suggested that the following serve as guides for grading oil by power factor tests.

- Oil having a power factor of less than 0.5 percent at 20°C is usually considered satisfactory for service.
- Oil having a power factor between 0.5 and 2 percent at 20°C should be considered as being in doubtful condition, and at least some type of investigation should be made.
- Oil having a power factor of over 2 percent at 20°C should be investigated and either reconditioned or replaced.

  The above-mentioned guides may be elaborated upon by saying that good, new oil has a power factor of approximately 0.05 percent or less at 20°C and that the power factor can gradually increase in service to a value as high as 0.5 percent at 20°9C without, in most cases, indicating deterioration to warrant investigation. When the power factor exceeds 0.5 percent, an investigation is indicated. The question of what decision to make regarding disposition of the oil depends on what is causing the high power factor. Dielectric strength tests should be made to determine the presence of moisture. The necessity for further tests will depend to a large extent on the magnitude of the power factor, the importance of the apparatus in which the oil is used, its rating, and the quantity of oil involved.