IEEE Guide to the Use of Gas-In-Fluid Analysis for Electric Power Cable Systems

Sponsor

Insulated Conductors Committee
of the
IEEE Power Engineering Society

Reaffirmed 8 December 2004
Approved 30 April 1998

IEEE-SA Standards Board

Abstract: The application of the analysis of gases dissolved in the fluids of fluid-filled cable systems is discussed with respect to the procedures for sampling, obtaining the dissolved gas data, and analyzing the results.
Keywords: aging, cable diagnostic, fluid-filled cable, gas analysis, remaining life, transmission cable

---

The Institute of Electrical and Electronics Engineers, Inc.
345 East 47th Street, New York, NY 10017-2394, USA

Copyright © 1998 by the Institute of Electrical and Electronics Engineers, Inc.
All rights reserved. Published 1998. Printed in the United States of America.

IEEE is a registered trademark in the U.S. Patent & Trademark Office, owned by the Institute of Electrical and Electronics Engineers, Incorporated.

ISBN 0-7381-0189-3

No part of this publication may be reproduced in any form, in an electronic retrieval system or otherwise, without the prior written permission of the publisher.

--`,,,`,`-`-`,,`,`,`,`---

Copyright The Institute of Electrical and Electronics Engineers, Inc.
Provided by IHS under license with IEEE
No reproduction or networking permitted without license from IHS

Not for Resale

IEEE Standards documents are developed within the IEEE Societies and the Standards Coordinating Committees of the IEEE Standards Association (IEEE-SA) Standards Board. Members of the committees serve voluntarily and without compensation. They are not necessarily members of the Institute. The standards developed within IEEE represent a consensus of the broad expertise on the subject within the Institute as well as those activities outside of IEEE that have expressed an interest in participating in the development of the standard.

Use of an IEEE Standard is wholly voluntary. The existence of an IEEE Standard does not imply that there are no other ways to produce, test, measure, purchase, market, or provide other goods and services related to the scope of the IEEE Standard. Furthermore, the viewpoint expressed at the time a standard is approved and issued is subject to change brought about through developments in the state of the art and comments received from users of the standard. Every IEEE Standard is subjected to review at least every five years for revision or reaffirmation. When a document is more than five years old and has not been reaffirmed, it is reasonable to conclude that its contents, although still of some value, do not wholly reflect the present state of the art. Users are cautioned to check to determine that they have the latest edition of any IEEE Standard.

Comments for revision of IEEE Standards are welcome from any interested party, regardless of membership affiliation with IEEE. Suggestions for changes in documents should be in the form of a proposed change of text, together with appropriate supporting comments.

Interpretations: Occasionally questions may arise regarding the meaning of portions of standards as they relate to specific applications. When the need for interpretations is brought to the attention of IEEE, the Institute will initiate action to prepare appropriate responses. Since IEEE Standards represent a consensus of all concerned interests, it is important to ensure that any interpretation has also received the concurrence of a balance of interests. For this reason, IEEE and the members of its societies and Standards Coordinating Committees are not able to provide an instant response to interpretation requests except in those cases where the matter has previously received formal consideration. Comments on standards and requests for interpretations should be addressed to:

Secretary, IEEE-SA Standards Board
445 Hoes LaneP.O. Box 1331
Piscataway, NJ 08855-1331
USA

Note: Attention is called to the possibility that implementation of this standard may require use of subject matter covered by patent rights. By publication of this standard, no position is taken with respect to the existence or validity of any patent rights in connection therewith. The IEEE shall not be responsible for identifying patents for which a license may be required by an IEEE standard or for conducting inquiries into the legal validity or scope of those patents that are brought to its attention.

Authorization to photocopy portions of any individual standard for internal or personal use is granted by the Institute of Electrical and Electronics Engineers, Inc., provided that the appropriate fee is paid to Copyright Clearance Center. To arrange for payment of licensing fee, please contact Copyright Clearance Center, Customer Service, 222 Rosewood Drive, Danvers, MA 01923 USA; (978) 750-8400. Permission to photocopy portions of any individual standard for educational classroom use can also be obtained through the Copyright Clearance Center.

Copyright The Institute of Electrical and Electronics Engineers, Inc.
Provided by IHS under license with IEEE
No reproduction or networking permitted without license from IHS
Not for Resale

Introduction

(This introduction is not part of IEEE Std 1406-1998, IEEE Guide to the Use of Gas-In-Fluid Analysis for Electric Power Cable Systems.)

This guide is intended for the engineering specialist interested in the evaluation and maintenance of fluid-filled cable systems including high-pressure fluid-filled and gas-filled pipe-type cables and self-contained cables operating at low, medium, or high pressure where the pressurizing medium is either a dielectric fluid or gas.

The use of dissolved gas analysis (DGA) began in the 1970s and has become an important tool for those who are responsible for the reliable operation of these cable systems. The technique requires removing a small sample of the pressurizing fluid and analyzing the gasses that are present in solution using a gas chromatograph. The results can provide clues as to the amount of thermal aging that the cable system has experienced and how this aging may be progressing in time, and also whether there may be problems in the system, especially in the vicinity of cable accessories such as splices and terminations that might require de-energization and repair.

The technology parallels the application of DGA to transformers as described in IEEE Std C57.104-1991. Following an historical background discussion, the fundamentals of gas generation in dielectric papers and fluids is presented as the basis for the technology. Sufficient data is presented so that the user can quantify the correlation of DGA data with the conditions that may have caused the gas generation.

Guidelines for the application of DGA and the methods used for sampling, analysis, and interpretation of the results are discussed in detail. Also covered are descriptions of other ancillary tests that can be done on the same samples to provide additional information as to the state of the cable system, and procedures that can be used to lower the discussed gas content when system operation may be jeopardized.

Finally, a reporting format is suggested, and a database that is maintained by ICC Working Group 5-28 is described.

Suggestions for improvement gained by the use of this guide are welcomed. They should be sent to the IEEE Standards Department.

The ICC Working Group 5-28 consisted of the following members:

John S. Engelhardt, *Chair*

Richard W. Allen, Jr.	Mark Floberg	Ronald J. Ponist
Paul Barry	S. Michael Foty	David Purnhagen
Thomas G. Campbell	Reza Ghafurian	Larry Tang
John H. Cooper	Mohammed Khajavi	Mark Todesco
Stanley J. Croall	Steve Kozak	Steven Waldorf
Roger Dashner	W. Graham Lawson	Jay A. Williams
Claus Doench	Marvin McGee	Shayne Wright
Roy Fleckenstein	Sven Olund	Joseph T. Zimnoch
	Gary A. Polhill	

The following persons were on the balloting committee:

Torben Aabo	Paul S. Cardello	John S. Engelhardt
T. J. Al-Hussaini	Thomas C. Champion	James Fitzgerald
R. W. Allen	Jack E. Cherry	S. Michael Foty
Theodore A. Balaska	John H. Cooper	Ronald F. Frank
Earle C. Bascom, III	Philip Cox	Robert B. Gear
M. Thomas Black	John R. Densley	Kenneth Hancock
David T. Bogden	Claus Doench	Jack Hand
Kent W. Brown	George S. Eager	Richard A. Hartlein

Copyright The Institute of Electrical and Electronics Engineers, Inc.
Provided by IHS under license with IEEE
No reproduction or networking permitted without license from IHS
Not for Resale

Wolfgang B. Haverkamp
Stanley V. Heyer
Lauri J. Hiivala
Stanley R. Howell
Richard Huber
Frank Kuchta
Jack Lasky
Gabor Ludasi
J. D. Medek
Andreas Meier
John E. Merando, Jr.
Daleep C. Mohla
James A. Moran
Shantanu Nandi
Harry E. Orton
Arthur V. Pack
Gary Polhill
Ronald J. Ponist
Dennis C. Pratt
Greg P. Rampley
Robert A. Resuali
Darrell E. Sabatka
Candelario de J. Saldivar-Cantu
Hazairin Samaulah
Ralph W. Samm
Gilbert L. Smith
Nagu N. Srinivas
Orloff W. Styve
John Tanaka
Austin C. Tingley
Steven P. Waldorf
Daniel J. Ward
Roland H. W. Watkins
J. A. Williams
Joseph T. Zimnoch

The final conditions for approval of this trial-use guide were met on 30 April 1998. This trial-use guide was conditionally approved by the IEEE-SA Standards Board on 19 March 1998, with the following membership:

Richard J. Holleman, *Chair*
Donald N. Heirman, *Vice Chair*
Judith Gorman, *Secretary*

Satish K. Aggarwal
Clyde R. Camp
James T. Carlo
Gary R. Engmann
Harold E. Epstein
Jay Forster*
Thomas F. Garrity
Ruben D. Garzon
James H. Gurney
Jim D. Isaak
Lowell G. Johnson
Robert Kennelly
E. G. "Al" Kiener
Joseph L. Koepfinger*
Stephen R. Lambert
Jim Logothetis
Donald C. Loughry
L. Bruce McClung
Louis-François Pau
Ronald C. Petersen
Gerald H. Peterson
John B. Posey
Gary S. Robinson
Hans E. Weinrich
Donald W. Zipse

*Member Emeritus

Kim Breitfelder
IEEE Standards Project Editor

Copyright The Institute of Electrical and Electronics Engineers, Inc.
Provided by IHS under license with IEEE
No reproduction or networking permitted without license from IHS
Not for Resale

Contents

1. Overview 1

1.1 Scope 1
1.2 Purpose 1

2. References 1

3. Definitions 2

4. Gases used in this guide 2

5. Historical background 3

5.1 The need for gas-in-fluid analysis 3
5.2 Historical use in transformers 4
5.3 Historical application to HPFF and SCFF cable systems 5
5.4 Methodology and refinements for special cases 5

6. Fundamentals of gas generation in cellulose and dielectric fluids 6

6.1 Mechanisms of gas generation 6
6.2 Rates of gas production for the various mechanisms 10
6.3 Determination of gas solubility 12
6.4 Dissolved gas distribution in bulk fluid 13

7. Application of gas analysis to cable systems 15

7.1 How to apply DGA 15
7.2 Number of samples and sampling locations 16
7.3 Scheduling sample acquisition 17

8. Sampling of fluid or gas from cable systems 17

8.1 Sampling objectives 17
8.2 Sampling equipment 18
8.3 Sources of fluid sample contamination 18
8.4 Sampling conditions 19
8.5 Preparation for sampling 19
8.6 Sampling procedure using the syringe method 20
8.7 Packaging and transport of samples 20

9. Analysis of fluid or gas samples 21

9.1 Gas analysis by chromatography using ASTM D3612-96 21
9.2 Gas analysis by other techniques 22
9.3 Appearance and physical tests 22
9.4 Dielectric tests 23
9.5 Chemical tests 23

10. Reporting of results 25

10.1 Data collection 25
10.2 Types of data 25
10.3 Method of collection 28

Copyright The Institute of Electrical and Electronics Engineers, Inc.
Provided by IHS under license with IEEE
No reproduction or networking permitted without license from IHS
Not for Resale

10.4 Recording format and units 28
10.5 Data presentation 28

11. Interpretation of results 28

11.1 Interpretation of the first round of DGA data 28
11.2 Changes in dissolved gas concentrations with time 31

12. Methods for treatment of systems with high gas content 31

12.1 Treating circulated pipe cable systems 32
12.2 Treating static pipe cable systems 32
12.3 Treating SCFF cable systems 32

13. The ICC database 33

13.1 Database software 33

14. Bibliography 34

Annex A (Informative) DGA Reporting forms 35

--`,,,`,`-`-`,,`,,`,`,,`---

Copyright The Institute of Electrical and Electronics Engineers, Inc.
Provided by IHS under license with IEEE
No reproduction or networking permitted without license from IHS

Not for Resale

IEEE Guide to the Use of Gas-In-Fluid Analysis for Electric Power Cable Systems

1. Overview

1.1 Scope

The scope of this guide is to furnish a basic understanding of the conditions that generate gases in fluid-filled cable systems, to establish a universal method of data collection and retention, to suggest guidelines for the evaluation of samples, and to recommend methods for treatment of systems with high gas content.

1.2 Purpose

This guide is intended to provide users of high-pressure fluid-filled (HPFF) pipe cable systems and self-contained fluid-filled (SCFF) cable systems with the basis to establish the use of gas-in-fluid analysis for diagnostic purposes and as an operating maintenance tool.

2. References

The following documents are relevant to the technology of gas-in-fluid analysis:

ASTM D2779-92, Standard Test Method for Estimation of Solubility of Gases in Petroleum Liquids.[1]

ASTM D2780-92, Standard Test Method for Solubility of Fixed Gases in Liquids.

ASTM D3612-96, Standard Test Method for Analysis of Gases Dissolved in Electrical Insulating Oil by Gas Chromatography.

ASTM D3613-92, Standard Test Methods of Sampling Electrical Insulating Oils for Gas Analysis and Determination of Water Content.

IEEE Std C57.104-1991, IEEE Guide for the Interpretation of Gases Generated in Oil-Immersed Transformers.[2]

[1]ASTM publications are available from the American Society for Testing and Materials, 100 Barr Harbor Drive, West Conshohocken, PA 19428-2959, USA.

[2]IEEE publications are available from the Institute of Electrical and Electronics Engineers, 445 Hoes Lane, P.O. Box 1331, Piscataway, NJ 08855-1331, USA.

Copyright © 1998 IEEE. All rights reserved.

Copyright The Institute of Electrical and Electronics Engineers, Inc.
Provided by IHS under license with IEEE
No reproduction or networking permitted without license from IHS
Not for Resale

3. Definitions

This clause defines terms used in this guide.

3.1 dissolved gas: Implies that the gas is dissolved in the dielectric fluid. In solution, these gases lose all semblance of gaseous matter. There are no gas bubbles in the fluid under normal circumstances, and there is little tendency for the gases to respond to gravitational forces. Dissolved gases will not accumulate at high points, and they generally do not pose any threat to the dielectric function of the fluid.

3.2 dissolved gas content: The amount of gas dissolved in the fluid expressed as a percent of, or in parts-per-million relative to, the volume of the fluid, where the volume of the gas is defined as that occupied by the gas at a pressure of one atmosphere and temperature of 0 °C. Dissolved gas content can refer to a specific gas, the total amount of all gases, or the total amount of combustible gases (TCG) only.

3.3 saturation: The amount of a particular gas that can be dissolved in a fluid at a given pressure and temperature. The saturation of all gases of interest is linearly proportional to absolute pressure. However, the effect of temperature varies with the specific gas. Some gases exhibit a decrease in saturation with increasing temperature while others tend to increase. The variation with temperature is generally small and can be neglected when evaluating fluid samples in the lab.

4. Gases used in this guide

The gases that are the subject of this guide are listed in Tables 1 and 2 by name and chemical symbol. Throughout this guide they may be referenced by either designation depending on context. While some users include the heavier hydrocarbon gases in their investigations, those listed form the basis of the technology at the time of publication of this guide. These lists may be expanded to include more gases in future revisions of this guide if sufficient data become available. Tables 1 and 2 also include the molecular weight (MW) and density at 0 °C, one atmosphere for each gas.

Table 1—Gases of interest for dissolved gas analysis (noncombustible)

Type of gas	Symbol	MW	Density (g/L)
Nitrogen	N_2	28	1.2507
Oxygen	0_2	32	1.4289
Carbon dioxide	CO_2	44	1.9768

Table 2—Gases of interest for dissolved gas analysis (combustible)

Type of gas	Symbol	MW	Density (g/L)
Carbon monoxide	CO	28	1.2501
Hydrogen	H_2	2	0.0898
Methane	CH_4	16	0.7167
Ethane	C_2H_6	30	1.3567
Ethylene	C_2H_4	28	1.2644
Acetylene	C_2H_2	26	1.1708

Copyright © 1998 IEEE. All rights reserved.
Copyright The Institute of Electrical and Electronics Engineers, Inc.
Provided by IHS under license with IEEE
No reproduction or networking permitted without license from IHS
Not for Resale

5. Historical background

5.1 The need for gas-in-fluid analysis

Safety, aesthetics, and the unavailability of lands for rights-of-way have made fluid-filled high-voltage cable circuits the principal method of delivering electric energy to the major urban centers of North America. The reliable operation of these circuits is critical to society in general and to utilities for which they represent a major capital investment. It is important to become aware of potential problems with these cable systems, which may have been overstressed, overheated, contaminated, mechanically damaged, or otherwise operated improperly.

Reliable operation requires thorough knowledge of a circuit's condition. With the age of existing HPFF pipe and SCFF cables approaching and in some cases exceeding their design life expectancy of 40 years, there is a need for methods that can help determine or establish the condition of these cable systems. The methods should identify and discriminate between problems of major and minor consequences, be repeatable, be able to localize a problem, be relatively simple to perform, and be inexpensive.

As direct observation of the cable's condition is basically impossible without de-energizing the circuit and removing cable for lab evaluation, alternate methods of monitoring the present condition and detecting possible degradation of cable insulation are needed. Gas-in-fluid analysis is the best option currently available to assess the condition of the cable's insulation system.

Degradation of the cable system's insulation or components beyond that expected during normal aging may be caused by any of the following:

- Thermal stresses developed at hot spot locations or areas that may have experienced over-temperature for any reason.
- Damaged shielding tapes caused by thermal-mechanical bending (TMB) activity, loose skid wires, excessive pulling forces, or damage prior to installation.
- Electrical stress concentrations sufficient to generate partial discharges of low intensity at operating voltage.
- Extreme electrical stress causing intense partial discharges in the dielectric.

Gas-in-fluid analysis, referred to as dissolved gas analysis (DGA), facilitates the observation of the by-products of this degradation through its environment, the insulating and pressurizing fluid. With periodic DGA, changes in the level of the by-products of cable degradation may be monitored, thus alerting the user to a potential problem with the cable system while providing important clues as to the exact nature of the problem.

DGA is a nondestructive procedure that requires obtaining samples of only the insulating fluid from the cable circuit. It is a precise but relatively simple operation that can be performed on a fluid sample taken from any available access point. As discussed in Clause 6, the types of gases present in the insulating fluid, their concentration, and their rates of production can provide insight into the condition of the cable dielectric and the cable shielding system. When performed in a consistent, systematic way and supplemented by dielectric, water content, and physical appearance tests carried out on the same sample, DGA allows an evaluation of the condition of the cable's internal components and early detection of potential problems. Since access points are normally installed at cable joints and terminations, problems detected can often be localized. Using standard sampling, analysis, and recording procedures, a current result can be compared to previous results to establish trends; and because of its relative simplicity, DGA can be performed on a routine basis with a minimum of service disruption and cost.

In some cases, problems may exist that do not occur within the dielectric but rather are associated with the shielding and grounding system. Such problems may include the sparking of skid wires to the pipe, overheated or burned shield leads due to induced currents or fault currents, and improperly grounded splice or terminal stress cone shields. These problems also produce distinctive gases, especially acetylene, that signal the need for internal maintenance.

Copyright © 1998 IEEE. All Rights Reserved.

--`,,,`,`-`-`,,`,,`,`,,`---
Copyright The Institute of Electrical and Electronics Engineers, Inc.
Provided by IHS under license with IEEE
No reproduction or networking permitted without license from IHS
Not for Resale

5.2 Historical use in transformers

DGA has been used to monitor the condition of transformers since the early 1970s. Experience with transformers prompted the earliest adaptations of DGA as a predictor of inherent problems. Continued work with DGA helped identify the source(s) of degradation and often led to corrective measures to preclude irreparable damage and to avoid the accumulation of the gases themselves, which could cause electrical breakdown.

A number of detectable gases are produced in varying rates and combinations by the effects of thermal and electrical stresses on traditional transformer insulation: cellulose paper, cottons, linens, fiber board, and insulating fluids. Gas concentrations are selectively characteristic of the incipient faults or distress that generate them. Improvements in sampling procedures and rapid evolution of sophisticated gas chromatography equipment coupled with modern computer graphics analysis have advanced DGA to a highly useful scientific methodology. On many occasions, prevention of service disruptions and avoidance of catastrophic failures of expensive transformers have been attributed to astute and timely DGA.

In 1977 the General Electric Company published a bulletin summarizing the application of DGA to transformers (Lyke, [B13][3]). The following discussion presents much of the information found in that bulletin.

Gases in varying amounts accumulate in transformers from the following interactions:

- Hydrogen evolved when moisture contamination causes oxidation of iron and steel components.
- Degradation due to high electrical stress and low intensity discharges, usually within the gaseous voids, characterized by large amounts of H_2 together with small amounts of the alkanes methane, ethane, and propane.
- Fluid degradation caused by thermal stresses that develop at hot spots in the metallic components and/or impregnated cellulose components. These are of an intermediate level of energy density and the products of decomposition again include hydrogen and alkanes, but the alkenes, ethylene and propylene, are also present in significant amounts, increasing in volume with increasing temperature.
- The decomposition of cellulose characterized by the generation of carbon monoxide and carbon dioxide with an increase of the ratio of CO to CO_2 indicating an increase in the exposure temperature.

The decomposition gaseous products of cellulose paper, cotton, linens, and pressboards are carbon monoxide, carbon dioxide, water, and hydrogen. For transformers, DGA has evolved into classifications of the gases by relative volume and diagnosis by study of the specific ratios of the gases. The higher the decomposition temperature, the larger is the ratio of CO to CO_2; this ratio is, therefore, a dependable analytical tool for estimating the maximum exposure temperature of cellulose-based materials.

Table 3 correlates the gases and gas ratios likely to be found as a result of various problems, reproduced from Table 2 of Lyke, [B13].

[3]The numbers in brackets correspond to those in the bibliography in Clause 14.

Copyright © 1998 IEEE. All Rights Reserved.
--`,,,`,`-`-`,,`,,`,`,,`---

Copyright The Institute of Electrical and Electronics Engineers, Inc.
Provided by IHS under license with IEEE
No reproduction or networking permitted without license from IHS Not for Resale

Table 3—Typical transformer problems and related dissolved gases

Occurrence	Typical gases evolved
Corona	H_2, CH_4, some C_2H_6 Ratio $CH_4/H_2 > 0.1$
Overheated metal @ 200 °C @ 400 °C @ 600 °C	H_2, CH_4, C_2H_6, C_2H_4 Ratio $C_2H_4/C_2H_6 = 0.4$ Ratio $C_2H_4/C_2H_6 = 1$ Ratio $C_2H_4/C_2H_6 = 1.5–2.0$
Arcing and sparking (visible/light)	C_2H_2 + others. Acetylene is almost always a sign of arcing.
Faults, degradation, involving cellulose (impregnated paper)	CO, CO_2, and H_2O. Ratio CO/CO_2 increases with temperature.

5.3 Historical application to HPFF and SCFF cable systems

The DGA technology has intrigued manufacturers and users of HPFF pipe and SCFF cable systems for many years. However, the realization that cable systems are configured and operate very much differently than transformers has dictated a cautious approach to the interpretation of DGA results. No universally accepted guidelines existed for analyzing the test results, and such data could not be relied on to provide sufficient information on the condition of a system to justify the expense for any corrective action, except for a few cases involving significant amounts of acetylene at terminations.

The first suggestion that DGA be used as a diagnostic tool was made by Lawson, Simmons, and Gale in a 1976 presentation (Lawson, et al., [B12]) that showed data on the gases produced during the thermal decomposition of cable papers in dry nitrogen.

In 1977, a New England utility performed DGA on 13 fluid samples taken from all accessible locations of a 26-year-old 6.8 km 120 kV HPFF pipe cable circuit. The circuit had performed exceptionally well with no problems since it was first energized. The fluid samples were taken because of the importance of the circuit and the concern that it was getting old. The intent was to try to learn something about the condition of the cables to avoid the serious consequence resulting from a failure and extended outage of the feeder.

Other utilities also began this same type of testing on old HPFF pipe and SCFF circuits with the same thought of trying to use the dielectric fluid as an indicator to help determine the condition of these early cable installations. Without guidelines for the interpretation of the results, these tests were always done in conjunction with other dielectric fluid tests including power factor, dielectric strength, moisture content, and color. This trend continued into the 1980s when a suggestion was made to start an Insulated Conductors Committee (ICC) project to study the gases evolved in pipe cable fluids. A new project, 5-28, was formed and the scope of the project was broadened to include both HPFF pipe and SCFF cable systems.

The first meeting was held at the April 1982 ICC meeting with an attendance of 40 members and guests. This high attendance at the inaugural meeting provided ample proof of the high level of interest in this subject. The attendance has continued to be high at all subsequent meetings with much participation and discussion of data by many involved in the cable industry.

5.4 Methodology and refinements for special cases

Several utilities have used DGA on HPFF pipe cable circuits for many years. The methodology consists of obtaining fluid samples at sampling valves on cable joints in manholes, at cable terminations, and in pumping plants, discussed more fully in Clause 8. Fluid samples have been taken according to ASTM D3613-92[4] using a syringe, stainless steel

[4]Information on references can be found in Clause 2.

Copyright © 1998 IEEE. All Rights Reserved.

--`,,,`,`-`-`,,`,,`,`,,`---

Copyright The Institute of Electrical and Electronics Engineers, Inc.
Provided by IHS under license with IEEE
No reproduction or networking permitted without license from IHS Not for Resale

bottle, tin can with flexible sides, or even a glass Mason jar. These samples were obtained on a periodic basis and analyzed according to the methods described in Clause 9. DGA gave the user the ability to confirm the presence and possibly classify the severity of the precursor conditions of an incipient fault.

Two anecdotal cases are presented here to show the value of DGA used by utilities to detect potential failures. Both of these cases involve HPFF cable systems: one in a joint and the other in a termination.

— The joint was on a 230 kV circuit and the utility had monitored high levels of hydrogen (5000–10 000 ppm) in that joint for some time. When the H_2 level reached 22 000 ppm, the circuit was de-energized and the joint disassembled. Examination of the splice revealed significant TMB damage, including carbonized tapes on one phase. A 9.15 m portion of this phase was replaced and the line put back in service.

— At a 345 kV HPFF-to-SF_6 termination, DGA showed high levels of acetylene and TCG. The acetylene level was 70–105 ppm where the normal level is below 5 ppm. The TCG level was 5500–6300 ppm versus a normal range of 400–800 ppm. Disassembly of the termination revealed internal arcing between the termination body and the cable stress cone shielding. The stress cone shielding insulation was rebuilt, and the line was re-energized.

Caution should be used when attempting to generalize the results of these cases. Prudent engineering judgment must be used to determine when a circuit should be de-energized and a joint or termination disassembled for examination and possible repair. The level at which the gas composition, concentration, or rates of generation would indicate component examination is discussed in Clause 11.

6. Fundamentals of gas generation in cellulose and dielectric fluids

6.1 Mechanisms of gas generation

Gases found in solution in cable fluids can be generated by several mechanisms. In general, the gases that are indicative of various aging mechanisms are the result of chemical changes in the major components of the system, the paper insulation, and the dielectric fluids used to impregnate the paper and maintain operating pressure. Chemical changes can be caused by high temperature thermal decomposition, electrical stress, ionization, and chemical reactions. Gases formed by such activity should contain only those elements present in the basic structure of the dielectric materials. Thus, cellulose can contribute only carbon, hydrogen and oxygen, and hydrocarbon-based dielectric fluids will provide only carbon and hydrogen, though both of these materials are likely to contain small amounts of nonhydrocarbon contaminants. Other gases are often present, the most common being nitrogen which is used to blanket fluid storage tanks of HPFF cable systems. Others are the result of contamination, either of the system or of the gas sample. The chemical processes that may be involved are briefly discussed below.

6.1.1 Thermal decomposition of cellulose

The thermal decomposition of cellulose-based dielectrics at temperatures of approximately 100 °C has been recognized for some time. In a 1935 article (Clark, [B4]) F. M. Clark noted that “[t]hese chemical changes not only produce increased power factor but are accompanied by gas formation with subsequent decrease in dielectric strength.” E. J. Murphy published articles on the thermal decomposition of cellulose in 1943 (Murphy, [B14]) and 1962 (Murphy, [B15]). In 1964 L. C. Flowers extracted moisture evolution rates from Murphy’s data (Flowers, [B6]). In 1977 W. G. Lawson et al, presented gas evolution rates specific to the thermal degradation of unimpregnated cable papers (Lawson, et al., [B12]), and in 1982 that work was supplemented by J. G. Head et al., working with impregnated papers exposed to simultaneous thermal and electrical stress (Head, [B8]).

The purest form of cellulose is a polysaccharide known as alpha-cellulose, which contains only carbon, hydrogen, and oxygen atoms in the ratio of $C_6H_{10}O_5$. The basic structure of the long alpha-cellulose chain is shown in Figure 1.

 Copyright © 1998 IEEE. All Rights Reserved.

Copyright The Institute of Electrical and Electronics Engineers, Inc.
Provided by IHS under license with IEEE
No reproduction or networking permitted without license from IHS Not for Resale

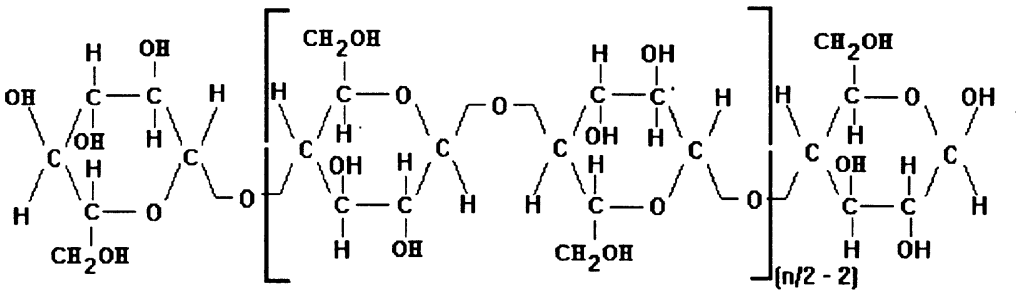


Figure 1—Basic molecular structure of alpha-cellulose

The "n" parameter denotes the length of the chain and will be roughly 1000 for typical cable papers as they leave the cable factory. This parameter is also known as the degree of polymerization (DP)

Kraft paper will contain from 40% to 80% alpha-cellulose. Papers with the higher percentage are used for extra-high voltage (EHV) applications requiring very low dielectric loss. The remaining material in Kraft paper will be variations of the cellulose chain structure known as the hemicelluloses, small amounts of lignin, an aromatic polymer binder present in the wood source, and traces of inorganic salts and other contaminants.

Cellulose is extremely hygroscopic; it readily absorbs free water and also contains chemically bound (adsorbed) water as part of its chain structure. The drying of cable paper to remove as much absorbed water as possible can be considered the first stage of its thermal aging history. Cable vacuum drying temperatures can reach 130 °C at which point the residual free water content will be less than 100 ppm and small amounts of adsorbed water will start to be removed. Fortunately this exposure is limited to a few days at most and the paper will suffer only a small reduction in DP.

Long-term aging in the 100 °C to 160 °C range results in the loss of hydrogen and hydroxyl side groups and the gradual decomposition of the cellulose chain at the end of the glucose units, which are nonreversible chemical reactions. When carbon atoms are freed they tend to form CO_2 first and then CO, which requires slightly more energy. Hydrogen, water, and small amounts of methane will be liberated. As might be expected, the presence of free oxygen will accelerate the decomposition processes and reduce the ratio of CO to CO_2 for a given aging temperature.

6.1.2 Effect of electrical stress on the decomposition of cellulose

The effect of electrical stress on the decomposition of cellulose is not well defined by specific mechanisms. One might expect that thermal decomposition reactions will be accelerated by electrical stress, which could provide additional energy to break the chemical bonds in the cellulose chain. However, data presented by Head et al. (Head, et al., [B8]) show clearly that the generation of CO_2 and CO in fluid-impregnated paper is not affected by the presence of electrical stress below the detectable ionization level, even though the generation of hydrogen and the hydrocarbon gases is accelerated with electrical stress. If discharge activity is present, the CO_2 and CO rates will increase; but it is not clear whether the stress contributes to the decomposition or simply acts to increase the local temperature.

6.1.3 Thermal degradation of dielectric fluids

Dielectric fluids are generally considered to be thermally stable over the complete range of operating temperatures applicable to fluid-filled cables. Thermal degradation processes do not become significant until the fluid is exposed to temperatures of approximately 150 °C.

Three types of dielectric fluids are found in cable systems. The oldest are mineral oils, which are highly refined fluids distilled from natural crudes; and the origin of the mineral oils determines the nature of the resulting fluid. The molecular structure of mineral oils consists of three chemical species: paraffins, naphthenes, and aromatics. The structures of these three components are shown in Figure 2 (Bartnikas and Srivastava, [B3]). "X" represents a possible point of connection between components.

Copyright © 1998 IEEE. All Rights Reserved.

Copyright The Institute of Electrical and Electronics Engineers, Inc.
Provided by IHS under license with IEEE
No reproduction or networking permitted without license from IHS
Not for Resale

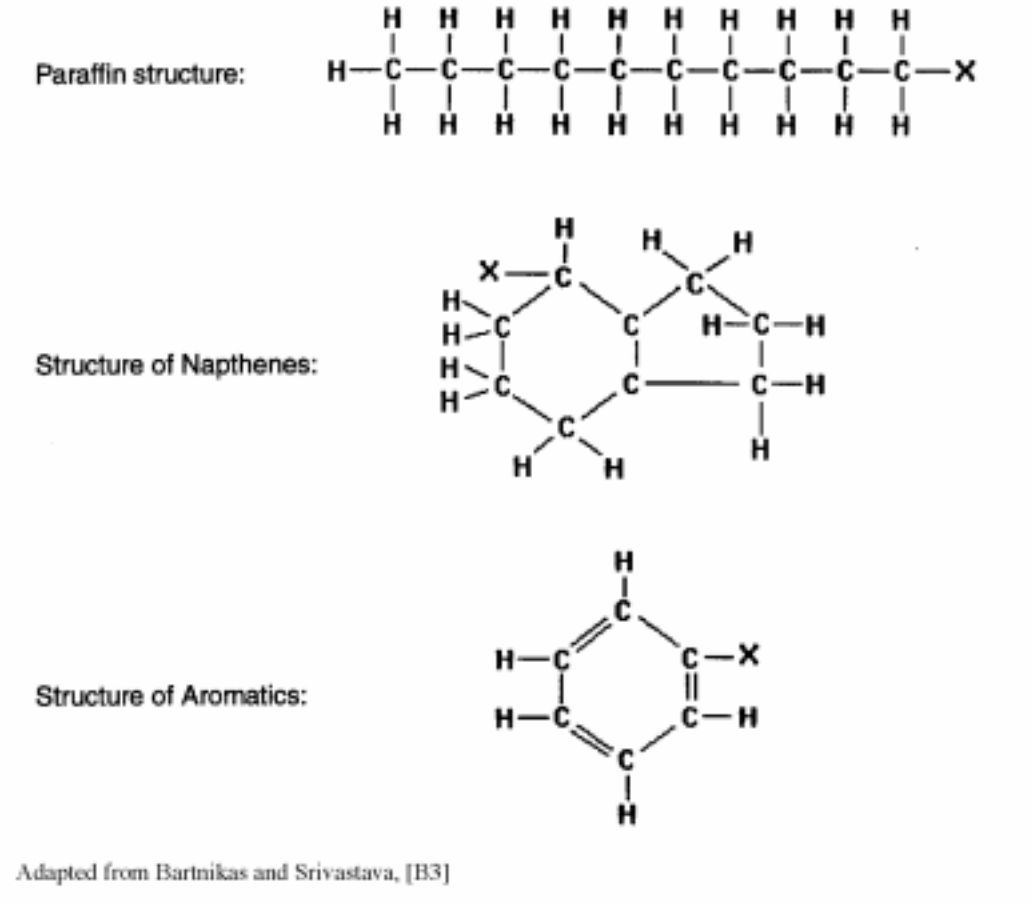


Figure 2—Chemical structure of mineral oil components

Polybutenes, synthesized from butene gas by catalytic polymerization, were first used in the 1930s to thicken mineral oil impregnants for use in gas-filled cables. In the late 1950s they began to be used as cable impregnants, and in the 1960s as pipe-filling fluids. Polybutenes were known for very low losses and excellent oxidation resistance. The chemical structure of polybutene, considered to be a partially unsaturated hydrocarbon because of the double carbon bond at the end of the molecular chain, is shown in Figure 3.

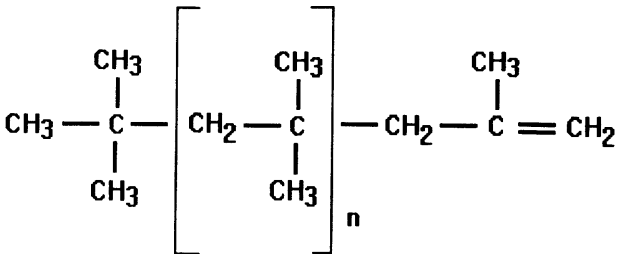


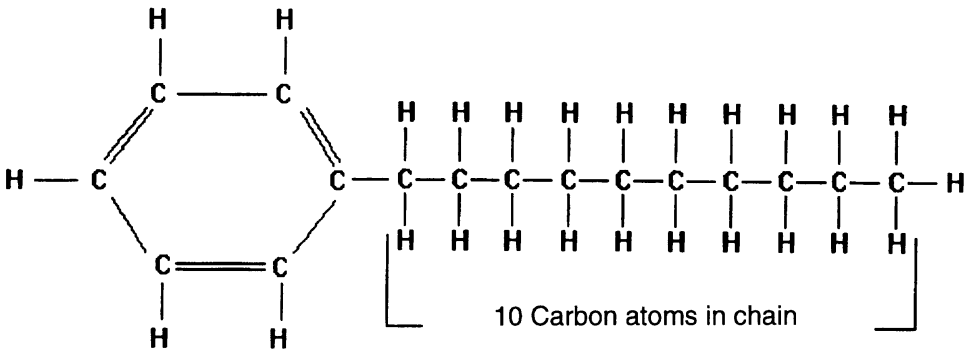
Figure 3—Chemical structure of polybutene

Alkylbenzenes are synthetic compounds that are made by the alkylation of an aromatic substrate with alkyl halides. Two versions are used as dielectric fluids: one has a linear chain structure emanating from the aromatic ring and is designated as “soft” while the other has a branched chain structure and is known as “hard.” The soft material is classified as a biodegradable material. The chemical structures of these two compounds are shown in Figure 4.

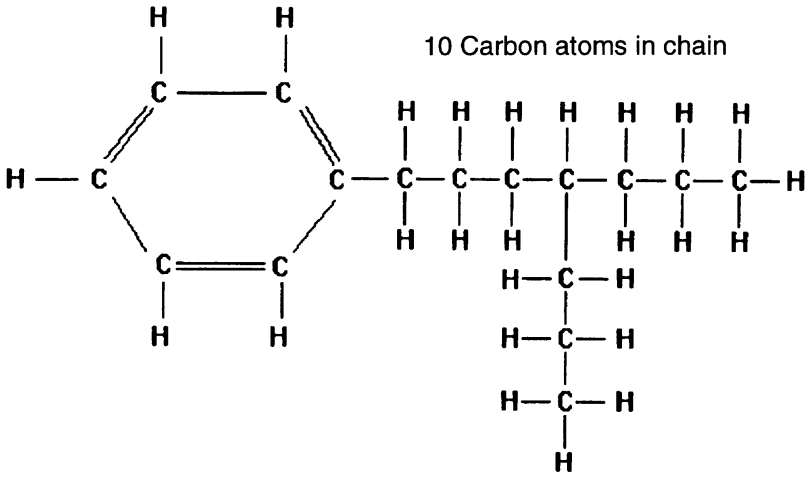
Copyright © 1998 IEEE. All Rights Reserved.

--`,,,`,`-`-`,,`,,`,`,,`---

Copyright The Institute of Electrical and Electronics Engineers, Inc.
Provided by IHS under license with IEEE
No reproduction or networking permitted without license from IHS Not for Resale



Structure of a Linear Alkylbenzene, “Decylbenzene”



Structure of a Branched Alkylbenzene, “Decylbenzene”

Figure 4—Chemical structures of alkybenzenes

Thermal degradation of these fluids starts with liberation of hydrogen and progresses as the temperature increases with the isolation of $(CH_2)_n$ groups as carbon-carbon bonds in the chains are broken. These groups combine with hydrogen atoms to form gases of the alkane group, the number of carbon atoms increasing with temperature. Above 200 °C double carbon bonds can be broken. At this point, the cyclic structure of naphthenes and aromatics can break, and unsaturated gases of the alkene series begin to be generated. Since no triple bonds exist in the various fluids, gases of the alkyne (acetylene) series must be formed from alkanes and alkenes. This process requires so much energy that sparking or electric arcs have to be present.

In general, even the breaking of a hydrogen bond to liberate a hydrogen atom does not begin at normal operating temperatures well below 100 °C. Therefore, if hydrogen and the alkanes are present in a cable system where overheating is not suspected, the cause is more likely due to electrical activity.

Increases in combustible gases caused by continuous pumping have been reported (ICC Minutes, [B10]). In one case, small gear pumps were found to generate combustible gases including 40 ppm of acetylene. In a study relating to heavily forced cooled cable systems, long-term tests with rotary screw pumps at 55 °C found the total amount of combustible gases (TCG) of 1000 ppm in polybutenes and 235 ppm in alkylbenzene, but no acetylene.

Copyright © 1998 IEEE. All Rights Reserved.

Copyright The Institute of Electrical and Electronics Engineers, Inc.
Provided by IHS under license with IEEE
No reproduction or networking permitted without license from IHS
Not for Resale

6.1.4 Electrical degradation of dielectric fluids

Dielectric fluids at temperatures in the normal operating range interact with hydrogen in the presence of ionization. This phenomenon has been used for years to evaluate fluids for low pressure applications in the well-known gas absorption tests. These tests, described as the Merrell test in ASTM D2298 [B1], or the modified Pirelli test in ASTM D2300-85(1991)e1 [B2], expose the fluid to a glow discharge in vacuum (Merrell test) or hydrogen (modified Pirelli test) and determine the amount of hydrogen evolved or absorbed by the fluid. While not well explained in the literature, the liberation of hydrogen must involve the breaking of hydrogen-carbon bonds accompanied by changes in the molecular structure of the fluid. Thus, the higher temperature mechanisms discussed above are probably supported by electric stress at lower temperatures, but most likely only in the presence of ionization. Likewise, the absorption of hydrogen in the modified Pirelli test is thought to be caused by attraction to the aromatic ring structure of mineral fluids and alkylbenzenes or the double carbon bond at one end of the polybutene chain. The saturated paraffinic fluid has the worst gas absorption properties because it lacks any double bonds.

While the term degradation implies that the molecular chain structure is broken apart, the higher energy available in the presence of ionization can also support polymerization or the combination of molecules with open carbon atoms. Since the fluid's viscosity is proportional to chain length, additional polymerization can result in an increase in viscosity rather than the decrease expected if chains are only broken, as in the degradation of cellulose and reduction of its DP.

6.2 Rates of gas production for the various mechanisms

Although interest in the aging of cellulose paper during the past 60 years has been considerable, most of the reported studies have been concerned with the deterioration of its physical and physico-chemical characteristics such as tensile strength, folding endurance, and degree of polymerization. By contrast, gas generation has been the subject of remarkably few quantitative assessments except those of Lawson (Lawson, et al., [B12]) and Head (Head, et al., [B8]) mentioned above. Those studies demonstrated conclusively that the gases produced during aging of alkylbenzene-impregnated paper resulted almost entirely from the thermal decomposition of the cellulose, and the contribution due to aging of the impregnant was negligible. These studies found that the rates of production of the important diagnostic gases can be quantified in terms of a zero order rate law of the form:

$$Q = Kt$$

where

Q is the quantity of gas produced
K is the rate constant
t is the aging time

K varies with temperature according to the Arrhenius relationship:

$$K = Ae^{\left(-\frac{B}{T}\right)}$$

where

T is the absolute temperature (°K)
A and B are the Arrhenius constants

Copyright © 1998 IEEE. All Rights Reserved.

Copyright The Institute of Electrical and Electronics Engineers, Inc.
Provided by IHS under license with IEEE
No reproduction or networking permitted without license from IHS Not for Resale

Head noted that data on gas production, water production, and the deterioration of physical and physico-chemical characteristics could all be represented by a single value of the exponential constant *B* (Head, et al., [B8]). He combined his aging data for all of the above parameters to obtain a best estimate of a "universal" *B*:

$$B = 15288 \pm 440\ ^\circ\mathrm{K}$$

Using this value of *B* and data fitting techniques, values of *A* for the various diagnostic gases were developed and are shown in Table 4.

Table 4—Summary of Arrhenius constant A and key gases (Head, et al., [B8])

Gas	*A* ($cm^3/g/h$)
Carbon monoxide	3.37×10^{12}
Carbon dioxide	1.97×10^{13}
Hydrogen	4.85×10^{10}
Methane	1.27×10^{10}
Ethane	5.24×10^{9}
Ethylene	2.58×10^{9}

These *A* values together with the *B* value reported above can be used to calculate the gas production corresponding to any aging temperature and exposure time of interest. For example, at 130 °C (403 °K), the calculations yield the results shown in Table 5. Also shown in Table 5 is the relative production of each gas normalized to the smallest, ethylene.

Table 5—Calculated aging at 130 °C using A and B constants suggested by Head (Head, et al., [B8])

Gas	Gas production rate ($cm^3/g/h$)	Relative production rates
Carbon dioxide	6.6×10^{-4}	7635
Carbon monoxide	1.1×10^{-4}	1305
Hydrogen	1.6×10^{-6}	19
Methane	4.3×10^{-7}	5
Ethane	1.8×10^{-7}	2
Ethylene	8.6×10^{-8}	1

Other published data sources are limited. Murphy (Murphy, [B15]) investigated the rates of evolution of carbon monoxide and carbon dioxide from dry Kraft paper. In the "steady state," following an initial period of high gas evolution attributed to the presence of impurities, he estimated the rate constant for carbon monoxide to be

$$K_{CO} = 6.24 \times 10^{14} e^{\left(\frac{17000}{T}\right)}$$

Copyright © 1998 IEEE. All Rights Reserved.

Copyright The Institute of Electrical and Electronics Engineers, Inc.
Provided by IHS under license with IEEE
No reproduction or networking permitted without license from IHS
Not for Resale

and the rate of evolution of carbon dioxide was found to be 2.5 times as great. In 1972 Hiro and Suganuma (Hiro and Suganuma, [B9]) determined the combined rate of evolution of carbon dioxide plus carbon monoxide in the temperature range 100 °C to 130 °C to be as follows:

$$K_{(CO+CO_2)} = 3.9 \times 10^9 e^{\left(-\frac{12000}{T}\right)}$$

For comparison purposes, the rates of evolution at 130 °C calculated using the rate constants developed by Head, Murphy, and Hiro and Suganuma are summarized in Table 6.

Table 6—Comparison of rates (cm^3/g/) of CO and CO_2 evolution at 130 °C

Gas	Head (Head, et al., [B8])	Murphy (Murphy, [B15])	Hiro (Hiro and Suganuma, [B9])
CO	1.1×10^{-4}	3.0×10^{-4}	Combined
CO_2	6.6×10^{-4}	7.5×10^{-4}	4.6×10^{-4}

Considering the 20-year span over which the experimental work was carried out and the probable differences in the materials tested as well as the techniques employed, the agreement among the data should be considered satisfactory.

6.3 Determination of gas solubility

Knowledge of the solubility of each gas likely to be present in a dielectric fluid is important to determine at what pressure a gas at some given concentration will form a gas bubble. The solubility parameters are also required for the calculation of the in-situ gas concentration following the sampling and gas extraction portion of the DGA procedure.

The solubility of a gas is expressed as the ratio of the volume occupied by all of the gas in a saturated fluid sample to that of the fluid sample, both volumes being at the same temperature and pressure. This ratio is known as the Ostwald coefficient and its experimental determination is described in detail in ASTM D2780-92 and ASTM D2779-92. The Bunsen coefficient is defined as the Ostwald coefficient at standard temperature and pressure (STP), the special case where the pressure is one atmosphere and the temperature is 0 °C. The Ostwald and Bunsen coefficients are commonly expressed as absolute ratios. The solubility can also be stated in ppm or percent, but is always based on the volumetric ratio.

The solubility of a gas in dielectric fluid is directly proportional to pressure and will vary up or down with temperature in a manner unique to each gas. A complete analysis will determine the Ostwald coefficient at several temperatures covering the range of interest. Data for “Petroleum Liquids” with a density of 0.85 are presented in ASTM D2779-92 in the form of a table of the Ostwald coefficients STP for several gases, supplemented by a graph of the variation of these coefficients with temperature over the range of –50 °C to 250 °C.

The gases of interest to DGA follow Henry’s law, which states that the ratio of the partial pressure exerted by a gas dissolved in a dielectric fluid to a reference pressure is equal to the ratio of the amount of gas dissolved in the fluid to that in the fluid when saturated at the reference pressure. When working with calculations involving quantities, it is convenient to recall that one mole of a gas occupies 22.4 L at STP and has a mass in grams equal to its molecular weight. For example, if nitrogen has a Bunsen coefficient of 0.1 in a fluid and the fluid is saturated at STP, then 224 ml of the fluid holds 22.4 ml of nitrogen at STP, and the nitrogen has a mass of 28 × .0224/22.4 = .028 g.

The procedure for determining solubility is to saturate a gas-free sample of the fluid with the gas of interest at a known pressure, usually one atmosphere, and at the temperature of interest and to measure how much gas is removed from the sample when the sample is completely degassed or degassed to some known lower pressure. An alternative approach is to measure how much gas is absorbed by the degassed fluid when the gas pressure and temperature are held constant at the point of interest.

Copyright © 1998 IEEE. All Rights Reserved.

Copyright The Institute of Electrical and Electronics Engineers, Inc.
Provided by IHS under license with IEEE
No reproduction or networking permitted without license from IHS Not for Resale

The Ostwald coefficients at atmospheric pressure and 25 °C are given in Section 8.5 of ASTM D3612-96 for a typical mineral fluid with a density of 0.855 g/cm^3 at 15.5 °C. The Bunsen coefficients for a similar mineral fluid are presented in ASTM D2779-92, Table 1 and/or Figure 1 for STP conditions. These two groups of coefficients are listed in Table 7 and illustrate the effect of temperature on the solubility of these gases, for this type of mineral fluid. These Ostwald coefficients are also those listed in Table 1 of the transformer DGA guide, IEEE Std C57.104-1978. IEEE Std C57.104-1991 lists slightly different Ostwald constants for a mineral fluid with a 0.880 density.

Table 7—Solubility coefficients at one atmosphere

Gas	Bunsen at 0 °C	Ostwald at 25 °C
Nitrogen	0.069	0.097
Oxygen	0.16	0.179
Carbon dioxide	1.45	1.17
Carbon monoxide	0.12	0.133
Hydrogen	0.04	0.056
Methane	0.42	0.438
Ethane	—	2.59
Ethylene	2.0	1.76
Acetylene	—	1.22

Mineral fluids found in cable systems tend to have densities that range from 0.89 to 0.94. The ASTM standards suggest that a linear density correction can be made using the following equation where $K_{0.85}$ is the Ostwald coefficient obtained from ASTM D3612-96 or Table 7. However, the use of this correction for mineral fluids whose density is above 0.90 is not recommended.

$$K_d = K_{0.85}\left(\frac{0.980 - d}{0.130}\right)$$

No data specific to cable-impregnating and pipe-filling fluids have been published. The values shown in Table 7 may be used with caution if no specific data are available. Any laboratory attempting to perform DGA should first determine the appropriate solubility coefficients for the gases and fluids under investigation.

In HPFF pipe cables, a nitrogen blanket is usually maintained over the dielectric fluid in the reservoir at a gage pressure in the range of 0.1–1 atmosphere (10–100 kPa). Therefore, N_2 gas concentrations in the range of 100 000–200 000 ppm can be expected in a properly operating system.

6.4 Dissolved gas distribution in bulk fluid

6.4.1 Diffusion in still dielectric fluid

Gases move through still dielectric fluid by molecular diffusion at an incredibly slow rate. The rate of diffusion will be proportional to the gas concentration gradient with a diffusion coefficient that is proportional to the absolute temperature and the root of the fluid's molecular weight and inversely proportional to the fluid's viscosity and the 0.6 power of the local gas concentration (Karger, et al., [B11]). While no specific data have been published, the following trends have been observed during theoretical studies of the subject:

— Gases would take months to years to diffuse from the cable surface throughout the cross-section of the pipe-filling dielectric fluid if it were still, and decades to travel axially along the cable to a convenient measurement point.

Copyright © 1998 IEEE. All Rights Reserved.

Copyright The Institute of Electrical and Electronics Engineers, Inc.
Provided by IHS under license with IEEE
No reproduction or networking permitted without license from IHS
Not for Resale

— The rate of gas diffusion increases 60- to 80-fold as the temperature of a given fluid increases from 20 °C to 80 °C.

— The rate of diffusion is typically 50 to 60 times faster in the pipe-filling fluid than it is in the cable impregnant.

— Hydrogen diffuses about 3 times faster than other gases.

The presence of the paper tapes in the bulk of the cable dielectric coupled with the higher viscosity of the impregnant will substantially reduce the rate of gas diffusion through the insulation system.

The gas distribution in both the cable insulation and the pipe filling dielectric fluid will, therefore, depend primarily on bulk mass transport of the dielectric fluid.

6.4.2 Types of dielectric fluid mass transport

There are three primary mechanisms of mass transport:

a) *Natural convection*. Natural convection loops are created when temperature gradients exist. Hot fluid rises. When fluid cools, its density increases, thus causing the fluid to sink. In static pipe cables, natural convection loops will exist that transport heat in the radial direction, and when the pipe is inclined, in the axial direction. The rate of mass transport in the radial direction can be inferred from empirically determined thermal resistances between the cable surface and the pipe wall. These thermal resistances are 100 times lower than those that would occur by pure conduction. The inferred circulation rates are about 4 L/h; and, as a result, the fluid in a local cross-section is completely recirculated every hour or two when the cables are loaded and temperature gradients are approximately 0.5 °C/cm. There may be a stagnant boundary layer at the cable surface of about 5–10 mm, however, which will be dependent on molecular diffusion only for gas transport. This implies that there may be a 30- to 60-day period for gases at the cable surface to traverse the boundary layer where bulk mixing by natural convection can take place.

   Natural circulation rates in the axial direction will vary with the degree of inclination and can be significant on steep slopes. At temperature gradients of about 0.1 °C/m, the bulk axial transport due to natural convection can approach 36 L/h, which is equivalent to an axial velocity of 1.5–3 m/h for typical systems. However, the distance traversed will be limited to the sloped section since the convection loop must be a closed loop.

b) *Forced convection*. Forced convection occurs when the fluid is propelled by an external force such as a pump. The fluids will simply move in the axial direction at the flow rate generated by the pump. Radial mixing is dependent on whether the flow regime is laminar or turbulent. In laminar flow, the radial transport by diffusion into the flow stream will be equivalent to that of natural convection flows. If the flow is turbulent, a more rapid and thorough mixing of gases coming out of the cables into the fluid will occur.

c) *Thermal expansion flows*. Fluid will move axially along the system due to thermal expansion and contraction resulting from the cable's load cycling and the gradual cyclic changes in the ambient. The volumetric expansion can be approximated by

$$V_x = .0008 V_t \Delta T$$

where

V_x is expansion volume, liters
V_t is total volume, liters
ΔT is change in temperature, °C

Therefore, a HPFF cable system with a volume of 24.8 L/m experiencing a 10 °C change of its fluid temperature will transport 0.1986 L in the axial direction for each meter of pipe. The effect is cumulative beginning with the point farthest from the pressurization plant. If the system were 15 km long, the maximum fluid movement would be 2979 L into or out of the pressurizing system.

Copyright © 1998 IEEE. All Rights Reserved.

Copyright The Institute of Electrical and Electronics Engineers, Inc.
Provided by IHS under license with IEEE
No reproduction or networking permitted without license from IHS Not for Resale

Fluid in the conductor and paper insulation will move radially in and out because of the volumetric changes associated with conductor temperature cycles. This phenomenon causes a gradual replacement of the impregnant with pipe fluid, working from the outside of the cable into the dielectric. This exchange will also take place axially in the conductor near terminations and splices. This fluid motion will accelerate the movement of dissolved gases generated in the dielectric into the bulk pressurizing fluid.

7. Application of gas analysis to cable systems

7.1 How to apply DGA

Once the decision is made to initiate a DGA program on a single circuit or an entire system, a systematic approach should be adopted. The program should be carefully designed before the first gas samples are taken so that the most information can be obtained in an efficient manner. The type of cable system and its hydraulic support equipment will dictate the details of the DGA program. Most self-contained cable systems and static pipe-type cable systems are amenable to sampling at every location where an access valve exists, as these systems experience little fluid motion. Conditions between sampling locations can be accessed by the bulk movement of an amount of fluid necessary to move the local fluid from the point of interest to the nearest sampling valve.

Pipe-type cable systems that utilize fluid circulation or oscillation will benefit from a different approach, as almost total mixing of the fluids justify system monitoring with only a few samples. However, fluid mixing will tend to mask localized problem areas. To explore local conditions it is necessary to operate the circuit in the static mode for at least one month to allow problem areas to generate sufficient gases for differentiation from the averaged background.

A plan and profile drawing package will show the location of terminations, manholes and joints, and the elevation profile of the cable system. Specifications of terminations and splices and historic operating characteristics for load and pipe temperature, if available, will prove useful in the analysis of gas content data. Assembling this information for all cable systems in the program before fluid sampling begins will help prioritize those circuits most susceptible to degradation.

The manufacturer and model of accessories should be identified and detailed drawings obtained before sample acquisition begins. Access points to the system can be located by referring to the original installation specifications. However, a thorough inventory by physical examination of the cable system is recommended. Examples of access points are valves or plugs located at the top of terminations, on the spool piece of termination assemblies, on splice sleeves, and at the trifurcators. Pumping plants have several access points located in the control panel and a drain valve is located on the storage tank. The size of access valves could range between 1/8 in on pumping plant instrument panels to 2 in on the casing of a splice or trifurcator. Any combination of pipe reducers, nipples, and couplings can be used to mate with the sampling equipment. These items are available at most hardware stores. When assembling this piping, care should be taken to achieve pressure-tight seals at each joint to avoid tainted test results.

When sampling terminations, the circuit should be de-energized to allow sampling from the top of the termination. Three samples can then be taken that represent the three areas of concern in a termination: the top volume that might contain a gas pocket, the middle portion where the fluid is highly stressed, and the lower portion that involves the stress cone and shielding associated with the semi-stop gland. This sampling is achieved by draining enough fluid to represent half of the fluid contained in the termination after taking the top sample. After obtaining the second sample representative of the middle of the termination, another half of the total volume is drained to obtain the bottom sample. If the circuit cannot be taken out of service, then the only access will be at the spool piece. In this case a single sample representative of the lower fluid is all that can be obtained, as fluid will flow upward from the riser pipe during sampling or draining.

If no access at a point is deemed critical for a thorough evaluation of the system, such as at a splice casing, methods exist for installing a valve assembly without draining the system. In general, the tapping method consists of welding a thread-o-let onto the pipe or casing, installing a double valve assembly into the thread-o-let and drilling or milling the

Copyright © 1998 IEEE. All Rights Reserved.

Copyright The Institute of Electrical and Electronics Engineers, Inc.
Provided by IHS under license with IEEE
No reproduction or networking permitted without license from IHS Not for Resale

final hole into the pipe with a drill or milling tool that has an O-ring seal and a long enough sealing shaft to permit withdrawal of the tool past the first ball valve so that the valve can be closed to remove pressure on the seal and permit removal of the tool. A tee is located near the inner valve to permit fluid flow to sweep the metal shavings into a waste container as soon as the tool penetrates the vessel. The line should be de-energized and the pressure lowered to approximately 400 kPa. Extreme caution should be taken when "tapping" the system. It is recommended that X-rays of the proposed location be taken to assure that no damage occurs to the cable or grounding assembly during the welding and drilling operations associated with the tapping procedure.

For circuits that utilize continuous fluid circulation, a single sample at any convenient location will be sufficient to monitor the state of the system. If the circulation rate is low (below 40 L/min), differences in the dissolved gases may exist between fluid samples taken from several splice casings because of stagnant fluid areas in the splice casing. This condition may be amplified when ambient temperatures are low and will favor sampling valves on the bottom of the casings. If a single sample is to be taken from a circulated system, enough fluid should be flushed before taking the sample to insure that fluid is being drawn from the flow stream, not a possibly stagnant portion of the local internal volume.

If surveying local areas of a circulated system is desired, circulation should be turned off for at least one month before sampling. Fall and spring usually are the best times to interrupt circulation for this purpose as loading during these periods is generally moderated, reducing the likelihood of overheating the uncirculated system. In some cases, however, this interruption may not be possible, especially if circulation is required to mitigate severe local thermal problem areas such as steam pipe or other circuit crossings.

7.2 Number of samples and sampling locations

Gases generated in a pipe or self-contained cable system can be very localized. With regard to gas generation caused by thermal degradation of the fluid-paper system because of high operating temperatures due to heavy loading, most of the gases will originate near the conductor. Their rate of diffusion out of the insulating papers into the pipe fluid will be extremely slow. This phenomenon means that gas generated due to internal degradation at only one location such as a joint or a steam crossing might not be present at other points along the cable system. Thus, taking sufficient fluid samples along the length of the cable circuit is important to obtain an accurate profile of gas content and, in particular, to identify sites of potential damage when operating temperatures are known to vary along the length of the circuit.

Sampling locations are often selected at existing valves to facilitate drawing the fluid sample. Typically, valves are installed on joint casings, spreaderheads, trifurcators, and potheads. Fluid samples are seldom taken from the cable line pipe simply because no valves are available. If valves are not installed at locations that are of interest for fluid sampling, the pipe tapping system mentioned in 7.1 should be considered as an option to allow installation of a valve on a fluid filled, pressurized cable pipe or joint casing without damage to the cables or contamination of the fluid.

Drawing a sample from a pressurizing plant or fluid reservoir is not likely to provide representative data unless fluid is being continuously circulated or oscillated through the pressurizing plant. On static systems, it may be possible to move fluid from an inaccessible location to a sampling valve by draining or adding a measured amount of fluid at the remote end of the system. Flow rates for such a block movement should be kept in the laminar flow range, well below the transition to turbulent flow.

The number of samples to be taken during each sampling period is dependent on the length and profile of the cable installation. Obviously, 20 km feeder demands that more samples be taken than a 1 km feeder. A cable system with a flat elevation profile might require less sampling then a cable circuit with numerous elevation changes.

The number of samples required for each cable circuit can be evaluated and optimized based on the data collected during the first few sampling periods when baseline initial data are being collected for a cable circuit. If data from all of the sampling locations are consistent, the number of sample locations can probably be safely reduced. Further, if fluid circulation is being used, the number of sample locations can be reduced since the moving pipe fluid is likely to provide more consistent readings representative of the average gas conditions for the circuit.

 Copyright © 1998 IEEE. All Rights Reserved.

Copyright The Institute of Electrical and Electronics Engineers, Inc.
Provided by IHS under license with IEEE
No reproduction or networking permitted without license from IHS Not for Resale

7.3 Scheduling sample acquisition

Gas-in-fluid sampling should begin before a new circuit is placed in service to establish benchmark conditions and be repeated once a year following the first two years of service. For a circuit already in service, the first round of samples will become the baseline for the continued monitoring of the circuit. If the initial results show low combustible gas contents and low rates of change, the sampling schedule could be extended to every three to five years depending on the degree of utilization of the circuit; heavier loadings would dictate a shorter sampling period. This schedule will establish a base case from which to compare subsequent data and help identify trends and characteristics of individual components in the system.

For systems with an established baseline and peak loads less than 75% of the cable system's normal rating, sample acquisitions could be extended to five-year intervals. The premise for this schedule is that these lines are not subject to the thermal and mechanical stresses that may be seen by more heavily loaded lines. Loading of all cable systems should be closely monitored between tests. The effect of load factor is not easily determined. Circuits that experience very high load factors, such as generator leads, will tend to reach higher operating temperatures, which will emphasize the paper decomposition gases. On the other hand, circuits with very low load factors and moderate to high peak loads will experience more cable movement and be at risk for TMB damage and shielding disturbances. The plan and profile of the system should be reviewed to determine whether extreme changes in elevation exist. In sections of the cable system with large slopes, the effects of gravity coupled with even moderate load cycling could cause cable movement and TMB not normally found in more heavily loaded systems without elevation anomalies. X-ray examination of cable joints can quantify the degree of cable movement and offers a nonintrusive method of tracking suspected movement.

If, during routine sampling, abnormal gas contents are identified in a particular component such as a splice, that location should be retested immediately to verify the initial findings. If the abnormal readings are confirmed, refer to Clause 12 for recommendations of methods for treating the cable system.

When beginning a DGA program on older cable systems, some components will likely exhibit what may appear to be abnormal gas contents when compared to similar components on the same line or other lines. The level of gases may not be high enough to be considered dangerous, but still justify cause for concern. Immediate retesting at these locations is recommended. If subsequent tests show elevated levels consistent with the initial findings, a "stepped up" sampling program may be appropriate. Analysis can be performed weekly, monthly, etc. until a definite trend or characteristic has been established. It may be desirable to flush several volumes of fluid and establish a new baseline. If the gas contents continue to rise at an abnormal pace, remedial action is indicated.

8. Sampling of fluid or gas from cable systems

8.1 Sampling objectives

The objective in sampling fluid from a cable system for DGA is to obtain accurate data from each sample extracted and to insure that the sampling on a given cable circuit provides an accurate profile of the dissolved gases along the length of the cable circuit, or, in the case of a circuit with fluid circulation or oscillation, provides a reasonable assessment of the average condition of the circuit.

To be fully effective, gas-in-fluid data must be collected over a period of years, providing comparative information regarding gas contents of the fluid over the life of the cable circuit. Since different individuals will be involved with sampling fluid from a cable over the cable system's life, developing and following a specific, detailed procedure for fluid sampling are important. This commitment is essential to insure that changes in sampling procedures do not occur that could affect the correlation of the data obtained.

Copyright © 1998 IEEE. All Rights Reserved.

Copyright The Institute of Electrical and Electronics Engineers, Inc.
Provided by IHS under license with IEEE
No reproduction or networking permitted without license from IHS Not for Resale

8.2 Sampling equipment

The equipment for collecting fluid samples for DGA analysis must ensure that contaminants do not get into the sample and that gases, including trace gases, do not escape from the sample. The preferred sampling equipment is the glass syringe and its associated methods, which are described in ASTM D3613-92.

The syringe is used because it allows for volume changes due to expansion or contraction of the fluid sampled. Glass hypodermic syringes of a suitable size with a Luerlock fitting and a three-way stopcock are effective for taking samples. The size can range from 25–250 cc, depending on the volume of fluid required for analysis. The most common sizes are 50 cc or 100 cc syringes. The syringe must be gas tight and should be cleaned and tested prior to use. Figure 5 shows a typical 100 cc glass syringe used for sampling pipe and self-contained cables.

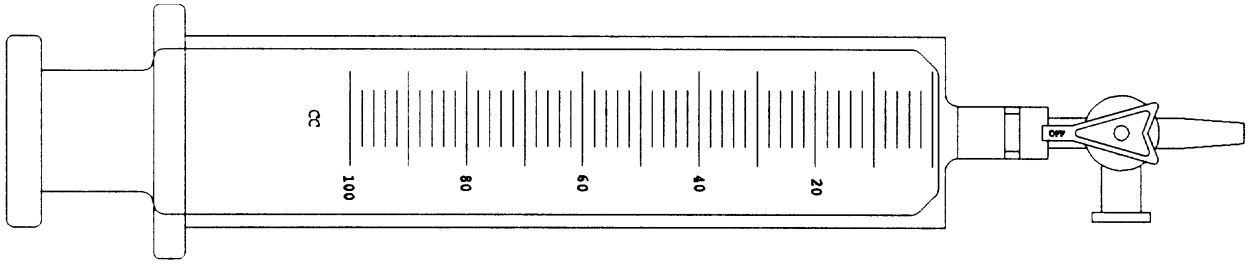


Figure 5—Typical glass syringe used for sampling cable fluids

A new proprietary sampling device, the EPRI Pressurizing Fluid Sampling System, or EPOSS cell, has been developed in an EPRI-funded program (EPRI EL-7488-L, [B5]). This system draws the sample into a pre-evacuated glass chamber, which is partially filled with the sample. The EPOSS cell maintains the sample under partial vacuum and serves as the degassing chamber for the laboratory analysis. The gases present in the head space of the cell are removed and quantified by gas chromatography.

8.3 Sources of fluid sample contamination

Fluid samples must be taken so that contaminants, whether solid, liquid, or gaseous, are not introduced into the sample and, at the same time, gases are not lost from the sample.

Contact of the fluid sample with the atmosphere and water or water vapor can change the types and amounts of gases identified. Impurities such as metals may also have degrading effects. Even metal sampling containers, regardless of how scrupulously cleaned, have been identified as a possible source of contamination by reacting with the sample under certain circumstances.

Glass containers are favored for collecting the fluid because properly cleaned glass does not introduce contaminants or chemically react with the fluid. Glass containers must be cleaned with suitable solvents followed by a wash with soap and hot deionized water prior to testing.

When acquiring samples from the storage tank, several liters of fluid should be flushed through the drain valve. This step will remove any contaminants that may have settled in the tank, such as flakes of paint or metal. Contaminants will be highest when flushing a tank that has very little fluid movement and has not been opened for years. Subsequent samples taken from the tank should produce little or no contaminants if sampling is maintained on a routine basis.

Copyright © 1998 IEEE. All Rights Reserved.

Copyright The Institute of Electrical and Electronics Engineers, Inc.
Provided by IHS under license with IEEE
No reproduction or networking permitted without license from IHS
Not for Resale

8.4 Sampling conditions

Reasonable sampling conditions should be maintained to minimize the possibility that contaminants will affect the samples or the samples will be modified due to handling conditions. All valves and fittings used for sampling must be thoroughly flushed.

It is desirable to do sampling when the relative humidity of the atmosphere is less than 75%. Samples should not be taken in the rain unless adequate protection is available to protect the sample from free water. To prevent condensation, the sample container and connection tubes or valves that are colder than the ambient temperature should be heated until their temperature is at or above ambient prior to taking the sample.

Some of the dissolved gases present in the fluid might be consumed by oxidation. This reaction can be delayed by preventing exposure to light. Thus, when glass vessels are used for sampling, care should be taken to avoid exposure to sunlight or extreme temperatures.

Metal body syringes (such as stainless steel syringes), stainless steel sampling bottles, or flexible sided metal cans, as described in ASTM D3613-92, are not recommended because there may be an interaction between some combustible gases and the stainless steel. Open body containers such as mason jars have been used with some success, but this type of container yields inconsistent results because both combustible and noncombustible gases will be lost and contaminated with air, regardless of how quickly the container is filled and sealed.

The tubing used to connect the cable equipment to the syringe must be impermeable and fluid-proof and should be kept as short as possible. Polytetrafluoroethylene (Teflon) or clear vinyl (Tygon) tubing is commonly used for this application.

When obtaining samples from HPFF pipe cables that use a nitrogen gas blanket in their storage tanks, the amount of dissolved nitrogen will likely result in a vapor pressure higher then one atmosphere. In fact, this pressure should approach the absolute storage pressure in the tank, which should always be slightly higher then one atmosphere. Since the glass syringe is an atmospheric pressure device, a gas bubble will form in the syringe shortly after obtaining the sample, or even while the sample is being drawn. This gas bubble must not be expelled from the syringe since it is part of the sample and must be included in the calculations of gas content. In addition, by the time the syringe reaches the lab for analysis, other gases in solution will have entered this gas space, thereby reducing their concentration in the fluid. Capturing all of the gases in the bubble is necessary to be sure that they are included in the quantification of the amount of each gas present in the sample before its pressure was reduced.

While the syringe is widely used and considered to be a gas-tight device, gases may escape from the syringe during long-term storage and handling. The best practice is to perform the gas chromatography as soon as practical after obtaining the sample.

8.5 Preparation for sampling

Regardless of the equipment used for sampling, flushing the sampling valve on the cable system is essential to ensure that it does not contaminate the fluid sample.

CAUTION — Drawing fluid samples from a system with a large fluid volume such as a pipe-type cable does not pose any risk to the equipment since the draining of a small sample will not affect the cable operating pressure. However, low volume systems such as low- and medium-pressure SCFF cables with small cores must be sampled carefully and slowly to insure that system pressure is not jeopardized.

Carefully inspect the valve to be used for sampling to be sure that it is in sound working condition, especially on old systems. Before removing the cap or plug, operate the valve several times to ensure its integrity. The valve cap or plug can then be removed and the inside of the valve cleaned with a clean, lint-free cloth to remove all visible dirt. Use of solvents for cleaning the valve is not recommended. The valve should be slowly opened to flush the valve body with fluid. Typically, 2–8 L of fluid should be flushed into a waste fluid container, consistent with the size and diameter of the component being sampled.

Copyright © 1998 IEEE. All Rights Reserved.

Copyright The Institute of Electrical and Electronics Engineers, Inc.
Provided by IHS under license with IEEE
No reproduction or networking permitted without license from IHS
Not for Resale

If the sampling valve is on the top of a pipe, casing, or pothead, check for any sign of free gas as fluid first leaves the valve. If sampling from the bottom of a casing, check for free water or visible debris and be prepared to salvage such material for identification and to try to ascertain its origin.

The flow from small sampling valves on low pressure systems may be very slow. It may be necessary to clean the valve passage with a short piece of wire or increase the local pressure if practical.

8.6 Sampling procedure using the syringe method

When sampling HPFF pipe cable systems, the sampling valve should be augmented by a small needle valve, which will allow the operator to throttle the fluid flow and prevent pressure build-up in the tubing connected to the syringe. Always close the sample valve while adjusting the position of the three-way valve on the syringe. Table 8 illustrates a sampling procedure using a syringe. Table 8 illustrates a sampling procedure using a syringe.

Table 8—Sampling procedure using a syringe

Step number	Step description
1	After the sample valve on the cable system has been flushed, attach the syringe to the sampling valve using a small piece of Tygon tubing and the appropriate fittings.
2	With the three-way valve on the syringe pointing toward the syringe, open the sampling valve and allow fluid to gently flow through the connection tubing past the three-way valve and into a waste fluid container. An additional liter should be flushed to clean the interconnecting tubing and the inside of the three-way valve.
3	When flushed, close the sampling valve and turn the three-way valve to point toward the waste container. Open the sampling valve and allow fluid to enter the syringe. The plunger should not be withdrawn, but allowed to move back under the pressure of the fluid. Allow the syringe to fill approximately 50%. There will be an air bubble visible in the syringe because of the dead space between the syringe and the face of the plunger. Close the sampling valve and turn the three-way valve to point toward the cable system while rotating the syringe to the vertical position. Then push the bubble and excess fluid out of the syringe, leaving the dead space full of fluid.
4	Turn the three-way valve toward the waste container and open the sampling valve to allow fluid to push the piston back until the syringe contains the desired amount of fluid. DO NOT pull the plunger manually, since this action would cause bubble formation.
5	Close the sample valve and point the three-way valve toward the syringe and disconnect the syringe from the tubing. If gas bubbles are present in the syringe, DO NOT attempt to expel them from the sample as this gas has come out of the fluid and must be included in the analysis.

8.7 Packaging and transport of samples

The syringe should be packaged and transported so that the syringe body is firmly held and protected from shock, but the plunger must be free to move. This arrangement allows the fluid sample to expand and contract as its temperature changes. When transported in this manner, the samples do not appear to be significantly affected by temperature cycling in transit. Fluid samples should be tested as soon as possible to avoid the possible loss of the lighter gases, which has been observed when syringes were left in storage for several weeks.

Copyright © 1998 IEEE. All Rights Reserved.

Copyright The Institute of Electrical and Electronics Engineers, Inc.
Provided by IHS under license with IEEE
No reproduction or networking permitted without license from IHS Not for Resale

9. Analysis of fluid or gas samples

9.1 Gas analysis by chromatography using ASTM D3612-96

Gas analysis by chromatography using ASTM D3612-96 covers the extraction and measurement of gases dissolved in electrical insulating fluid having a viscosity of 100 Saybolt Universal seconds (SUS) or less at 40 °C. Dielectric fluids having higher viscosities, which include most HPFF cable system fluids, are theoretically outside the scope of this method. In practice, however, ASTM D3612-96 has been found to be applicable to fluids having viscosities as high as 750 SUS.

The extraction of the gases from the fluid sample is accomplished by injecting a known amount of fluid into a pre-evacuated degassing flask connected to a large collecting flask and stirring the fluid to allow the dissolved gases to come out of solution and reach an equilibrium between the gas space and the fluid. The fluid is then isolated from the collection flask and the gases in the collection flask are compressed to atmospheric pressure and their volume is measured. This gas volume is then ready to be sampled, usually by a small gas-tight injection syringe, and injected into the sampling port of the gas chromatograph.

The calculations require precise measurement of all of the volumes associated with the apparatus to allow the conversion of the final volume for each gas detected in the chromatograph to its concentration in the gas space over the fluid sample and finally to the concentration in the fluid sample. This conversion is done by calculating a degassing efficiency with the aid of the Ostwald coefficients that apply to the fluid type and its temperature during the degassing period.

9.1.1 Modifications to ASTM D3612-96

a) As outlined in ASTM D3612-96, the extracted gases are analyzed by using a gas chromatograph. The procedure is not rigidly specified and can be modified to extend to the identification and determination of hydrocarbon gases of higher molecular weight than those mentioned in Clause 4.

b) Warming the fluid samples with a heat lamp has been found to be of assistance when handling higher viscosity fluids. The fluid temperature should be measured during the final stages of the degassing step and possibly controlled to correspond to the available Ostwald coefficient temperatures.

c) The 10-min stirring and degassing time called for in paragraph 9.6 of ASTM D3612-96 should be extended at least another 10 min with higher viscosity fluids to ensure equilibrium.

9.1.2 Problems and limitations

Fluid samples for this method should be taken according to ASTM D3613-92 in glass syringes. Occasionally bubbles will be found in gas-saturated samples. The gas bubble volume should be measured while still in the syringe, and this volume must be assigned to the entire sample. There are several ways to include the bubble in the measurement. The most direct is to inject just the bubble into the degassing chamber, isolate a portion of it in the collection flask, compress it, sample it and analyze it in the chromatograph. Then re-evacuate the apparatus and analyze the fluid sample in the normal manner. The gas volumes determined for the bubble are assigned to the entire fluid sample volume. The proportions belonging to the analyzed sampled are then added to the gas volumes determined from the analyzed sample in the ratio of the sampled volume to the total fluid volume. Other methods of measuring and accounting for the gases in the bubble may be used as long as these gases are included in the final tally of gases in the correct volume ratios.

Incomplete degassing of the fluid sample will lead to errors in the final results. Vigorous mixing during the degassing stage is necessary and should continue until no bubbles are visible in the fluid. Small vacuum leaks will also lead to errors by overstating the amounts of nitrogen and oxygen in the sample.

Copyright © 1998 IEEE. All Rights Reserved.

Copyright The Institute of Electrical and Electronics Engineers, Inc.
Provided by IHS under license with IEEE
No reproduction or networking permitted without license from IHS
Not for Resale

9.2 Gas analysis by other techniques

9.2.1 ASTM methods for total gas content

ASTM D2945-90 and ASTM D831-94 describe similar methods to measure the total gas content of dielectric fluids with a viscosity up to 100 SUS and 1000 SUS, respectively. The latter method employs a cold trap to eliminate condensable vapors, basically water vapor, from the gas measurement. Both methods degas the fluid by introducing it into an evacuated apparatus and measuring either the volume of gas evolved from the sample (ASTM D2945-90), in the same way as ASTM D3612-96, or the final pressure in the gas space above the sample (ASTM D831-94). These methods, especially ASTM D2945-90, are most useful for low-pressure SCFF cable system maintenance and monitoring the performance of degassing equipment, where total gas contents must be low.

ASTM D1827-92(1996)e1 sweeps dissolved gas from the fluid sample with a stream of CO_2. The swept gases and CO_2 are bubbled through a potassium hydroxide solution that completely removes the CO_2 but passes the other gases. The volume of gas collected is related to the fluid volume as the total gas content, minus any CO_2 that may have been in the fluid. This method is not considered useful for the analysis of cable fluid gas contents.

All of these methods can be modified by fitting a septum to the collection apparatus so the collected gases can be sampled with a gas-tight syringe and analyzed by gas chromatography as in ASTM D3612-96.

9.2.2 Semipermeable membranes

Instruments are available that utilize a semipermeable membrane to separate dissolved gases from fluid samples. Only hydrogen diffuses through the membrane in significant quantities. Larger gas molecules diffuse through in lesser amounts. The resulting analysis is skewed in favor of the smallest gas molecules. The usefulness of the analysis is thereby limited. This technology has found wide application in real-time instruments that monitor combustible gas contents by the output of a fuel cell that burns the gases that pass through the membrane.

9.3 Appearance and physical tests

9.3.1 Visual inspection

Report qualitative observations. Examples of comments are “fluid is cloudy,” “hazy,” “solid particles present,” “clear,” “bright,” “free of sediment,” and “dark.”

If fluid is hazy or cloudy, it could contain water or other material in a colloidal suspension. If heating to 100 °C clears the sample, then the cloudiness is most likely due to the presence of free water. If heating does not clear the sample, sparge the sample by bubbling nitrogen through the sample while heating to about 100 °C for 15 min, then repeat the observations. The nitrogen should remove the cloudiness.

NOTE — The following analyses (except for water content) should be performed on samples sparged with nitrogen as described above.

9.3.2 Color using ASTM D1500-96

a) *Summary of method*. The sample is placed in a glass sample jar. The color of the sample by transmitted light is compared with a series of tinted glass standards. The glass standard best matching the sample is selected; or, if an exact match is not possible, the next darker glass is selected. The results are reported numerically on a scale of 0 to 8.0.

b) *Significance*. An increase in color during service is an indicator of deterioration, oxidation, or contamination.

Copyright © 1998 IEEE. All Rights Reserved.

Copyright The Institute of Electrical and Electronics Engineers, Inc.
Provided by IHS under license with IEEE
No reproduction or networking permitted without license from IHS Not for Resale

9.3.3 Viscosity using ASTM D88-94 or ASTM D445-96

a) *Summary of methods*. ASTM D88-94 measures the Saybolt viscosity while ASTM D445-96 measures the kinematic viscosity. ASTM D2161-93 provides the method for converting the kinematic viscosity to SUS. Both methods measure the time for a fixed volume of liquid to flow either through the capillary of a calibrated viscometer (ASTM D445-96) or through a calibrated orifice (ASTM D88-94).

b) *Significance*. An increase in viscosity during service may be due to polymerization of the fluid or extraction of polymeric material from the system or both. A decrease in viscosity may be the result of molecular chain scission caused by thermal or electrical degradation that has also produced gaseous by-products.

9.4 Dielectric tests

9.4.1 Dissipation factor (power factor) and relative permittivity (dielectric constant) using ASTM D924-92

a) *Summary of method*. The fluid sample is tested in a three-terminal or guarded-electrode test cell maintained at the desired temperature, typically 100 °C. The dissipation factor and capacitance are measured at 60 Hz using a bridge circuit with a standard gas-filled capacitor, following the instructions appropriate to the bridge being used. For routine tests, a two-electrode cell may be used. Dissipation factor measured at room temperature will always be lower and of no value.

b) *Significance*. A fluid's dissipation factor, which is equal to its power factor at the low levels typical of dielectric fluids, should remain low throughout the fluid's service life. However, the by-products of thermal and electrical degradation will cause an increase in dissipation factor, as will various types of contamination. If the dissipation factor gets too high, the dielectric properties of the insulation system may be affected and ultimately lead to service failures. A maximum value of 0.5% at 100 °C is thought to be a prudent limit for satisfactory operation. If the dissipation factor is higher than this value, fluid treatment should be considered.

9.4.2 Dielectric strength using ASTM D877-87(1995)

a) *Summary of method*. The insulating liquid is tested in a test cup between two 1 in (25.4 mm) diameter disk electrodes spaced 0.100 in (2.54 mm) apart. A 60 Hz voltage is applied between the electrodes and raised at a uniform rate of 3 kV/s. The voltage at which the current in the liquid reaches 2–20 ma and trips a circuit breaker is the dielectric breakdown voltage.

b) *Significance*. A reduction in dielectric strength during service indicates the presence of contaminants such as water, dirt, or conducting particles.

CAUTION — Low dielectric strength may also be due to the introduction of impurities during sampling or the release of gas bubbles during the test because of a drop in temperature of the liquid. If warming the liquid increases its dielectric strength, gas bubbles were probably the cause of the reduced levels.

9.5 Chemical tests

9.5.1 Water content using ASTM D1533-96 (Karl Fischer method)

a) *Summary of method*. This method is based on the reduction of iodine by sulfur dioxide in the presence of water. A chloroform/methanol solvent is used with Karl Fischer reagent, which changes color when water is fully reacted. The titration is repeated after the sample is added to the solvent and the amount of reagent needed to rebalance the mixture is a direct measure of the amount of water present in the sample.

b) *Significance*. An increase in water content during service may be due to introduction of water during a repair. A second source for an increase in water content of the dielectric fluid is thermal degradation of the paper insulation. Water generated by this phenomenon will tend to stay in the paper. Temperatures approaching

Copyright © 1998 IEEE. All Rights Reserved.

Copyright The Institute of Electrical and Electronics Engineers, Inc.
Provided by IHS under license with IEEE
No reproduction or networking permitted without license from IHS
Not for Resale

100 °C are required, which will occur deep in the insulation. The water resulting from these high temperatures will be absorbed by the cooler outer portion of the insulation wall. The dielectric fluid will absorb only a small percentage of the water so produced.

9.5.2 Neutralization number using ASTM D664-95 or ASTM D974-97

a) *Summary of methods*
   1) ASTM D664-95. The sample is dissolved in a mixture of toluene and isopropyl alcohol containing a small amount of water and titrated potentiometrically with alcoholic potassium hydroxide solution.
   2) ASTM D974-97. The sample is dissolved in a mixture of toluene and isopropyl alcohol and a small amount of water. The resulting single-phase solution is titrated with alcoholic acid solution using p-naphtholbenzene as an indicator by change of color.

b) *Significance*. An increase in acid number could result from oxidation and, therefore, might suggest the presence of oxygen or peroxides in the system. A high neutralization number is usually accompanied by high power factor.

9.5.3 Chlorine, organically bound using ASTM D2522-95

This test should only be performed if the dielectric fluid structure is likely to contain chlorine. ASTM D2522-95 was developed for polybutene dielectric fluids.

a) *Summary of method*. Organically bound chlorine is converted into sodium chloride by reaction with sodium biphenyl solution. The sodium chloride is extracted with dilute nitric acid, and the chlorine content of the aqueous phase is determined by potentiometric titration.

b) *Significance*. This test is used primarily as a quality control on the production process monitoring the removal of hydrochloric acid. The limits for new polybutene fluids range from 20 ppm to 50 ppm by weight. An increase in chlorine content during service would likely be due to the formation of hydrogen chloride, which would probably react with metals in the system.

9.5.4 Inorganic chlorides using ASTM D878-96

a) *Summary of method*. The dielectric fluid is extracted with water. The water layer is tested with silver nitrate for the presence of chlorides.

b) *Significance*. No inorganic chlorides should be in a polybutene system. The presence of inorganic chlorides indicates that chlorine residuals in the polybutene have split off as hydrogen chloride during service and reacted with inorganic materials.

9.5.5 Peroxide number using ASTM D1563 (discontinued 1985)

a) *Summary of method*. A sample is dissolved in carbon tetrachloride and contacted with aqueous potassium iodide. The iodide liberated is titrated with sodium thiosulfate solution. The results are calculated to parts per million of oxygen.

b) *Significance*. An increase in peroxide content during service indicates the presence of oxygen in the system. Peroxides react with metals in the cable system to form metallic salts which cause the power factor of the fluid to rise dramatically. Therefore, the peroxide content should be kept as low as possible.

9.5.6 Metal content via emission spectroscopy

Significance. An increase in metal content in the form of very small particles during service may have a significant negative effect on electrical properties, especially dielectric strength. This is particularly true in areas where the bulk fluid is stressed, as in terminations and SCFF feed joints.

 Copyright © 1998 IEEE. All Rights Reserved.

Copyright The Institute of Electrical and Electronics Engineers, Inc.
Provided by IHS under license with IEEE
No reproduction or networking permitted without license from IHS Not for Resale

10. Reporting of results

10.1 Data collection

If a DGA program is being initiated, a data reporting format should be developed. Such a format has been created by ICC Working Group 5-28, and a database has been established that includes DGA data inputs from several users. The two data forms are described in this clause and the database is described in Clause 13. Utilization of the 5-28 data forms is recommended as this use will facilitate the sharing of data by entering them into the ICC Working Group 5-28 database.

A consistent collection of gas-in-fluid data will allow the user to track the condition of operating cables. When the information is stored in a common format, data can be compared to the results from several other companies. This ability to compare has the effect of broadening the sample and experience base while minimizing its cost.

10.2 Types of data

a) *System descriptive data*. A physical description of each cable installation is required to aid with the analysis of the DGA data and to assist in the comparison with data from other systems. This information ensures that comparative analyses can be carried out effectively with data from cable systems of other utilities. Similarly, information on the operating history of the cable is helpful to permit evaluation of changes that might be due to thermal aging or to definitively rule out thermal aging if the circuit loading is known to be low. The recommended reporting format is shown in Figure 6.

b) *DGA data*. Each gas analysis sample must be sufficiently identified to allow comparison with previous or subsequent samples taken at the same location. The recommended reporting format is shown in Figure 7. This form provides six columns for individual data. Data can be grouped according to a specific location where each column presents data for a particular date, or grouped for a common date where each column presents data from a different sample location on the circuit.

Copyright © 1998 IEEE. All Rights Reserved.

--`,,,`,,`-`-`,,`,,`,`,,`---
Copyright The Institute of Electrical and Electronics Engineers, Inc.
Provided by IHS under license with IEEE
No reproduction or networking permitted without license from IHS
Not for Resale

ICC Working Group 5-28 GAS-IN-FLUID ANALYSIS

Reporting Form #1—Cable System Description

This form is used to describe a particular circuit on a utility system and should be submitted only once, unless an historical update is required.

UTILITY XYZ Company
Circuit Designation X-999

Nominal Voltage 230 kV
Cable Type HPFF Pipe
Circuit Length 68,000 ft
Number of Joints 29
Year of Installation 1967

CABLE DETAILS
Cond. Size 2500 kcmil
Cond. Material Copper
Ins. Thick 760 mils
Impreg. Type SUN XX
Manufacturer(s) ACME
Skid Wire Mat'l Brass

PIPE DETAILS
Size 10 3/4 × 1/4 in
Internal Coating Endcor
Filling Fluid SUN #6
Approx. Quantity 200,000 ga

OPERATING DETAILS
Storage Tank Gas Pressure & Gas Type Nitrogen 3 psig
Fluid Circulation No
Max. Oper. Pressure 260 psig
Min. Oper. Pressure 75 psig
Elevation Difference—Pothead to Pumping Plant 80 ft
Elevation Difference—Max. Pipe Elev. to Pumping Plant 360 ft

CABLE HISTORY
Faults in System? No
Leaks? No
Accidental Pressure Loss? No
Welding on Fluid-Filled Pipe or Pipe Casings? No
Welding on Drained Pipe or Pipe Casings? Yes
Filling Fluid Changes? No
Circuit Modifications? No

BRIEF DESCRIPTION: This circuit feeds a downtown substation. It is typically loaded to about 60% of its rating during summer months and about 40% of its rating in winter.

Figure 6—A completed example of Reporting Form #1, Cable System Description

Copyright © 1998 IEEE. All Rights Reserved.

Copyright The Institute of Electrical and Electronics Engineers, Inc.
Provided by IHS under license with IEEE
No reproduction or networking permitted without license from IHS
Not for Resale

ICC Working Group 5-28 GAS-IN-FLUID ANALYSIS

Reporting Form #2—Gas Analysis Data

UTILITY XYZ Company **CIRCUIT DESIGNATION** X-999

FLUID SAMPLE DATA

Sample Number	**1**	**2**	**3**	**4**	**5**	**6**
Identification	S1	S2	S3	S4	S5	S6
Location	Term-A	Jt-3	Jt-9	Jt-16	Jt-23	Jt-28
Size	100 cc	100 cc	100 cc	100 cc	100 cc	100 cc
Container Type	Syringe	"	"	"	"	"
Sample Time	7:25A	8:45A	9:45A	11:00A	1:20P	2:45P
Sample Date	8-24-89	"	"	"	"	"
Test Date	8-26-89	"	"	"	"	"

GAS-IN-FLUID DATE—% OF FLUID VOLUME OR PPM BY VOLUME

Nitrogen %	6.40	2.81	0.61	0.23	0.16	0.52
Oxygen %	0.21	0.17	0.09	0.08	1.21	0.76
CO_2—ppm	436	349	687	56	122	535
CO—ppm	76	35	28	8	43	89
Hydrogen—ppm	327	540	248	642	187	851
Methane—ppm	32	6	13	21	64	96
Ethane—ppm	159	43	87	109	168	241
Ethylene—ppm	37	13	17	24	66	134
Acetylene—ppm	0	0	0	0	0	8
Other Hydrocarbons	–	–	–	–	–	–
Total Combustible Gas—ppm	631	637	393	804	528	1419
Total Gas %	6.72	3.08	0.81	0.40	1.44	1.48

Figure 7—A completed example of Reporting Form #2, Gas Analysis Data

Copyright © 1998 IEEE. All Rights Reserved.

Copyright The Institute of Electrical and Electronics Engineers, Inc.
Provided by IHS under license with IEEE
No reproduction or networking permitted without license from IHS
Not for Resale

10.3 Method of collection

The recommended method of collection is described in Clause 8. The actual method of collection may vary from company to company due to internal practices. To ensure consistent inputs for the database, the methods employed should produce results equivalent to the technique referred to in this guide.

The DGA should be performed as soon as practical after the samples have been taken. A recommended method for the DGA is described in Clause 9. Other methods may be used that produce equivalent results.

10.4 Recording format and units

The two report forms adopted by this guide are shown in Figures 6 and 7. Each is shown as a completed example. The blank forms are presented in Annex A, and are suitable for reproduction.

a) Reporting Form #1, Cable System Description. The reporting format and suggested units for Form #1 are shown by example in Figure 6.

b) Reporting Form #2, Gas Analysis Data. The reporting format and suggested units for Form #2 are shown by example in Figure 7. The amount of nitrogen, oxygen, and total gas content shall be recorded on Form #2 as a percent of fluid volume. All other gases and the total combustible gases should be recorded on Form #2 in ppm.

10.5 Data presentation

The information within the database is available to all users and can be presented for comparison in any format needed by the user. The only requirement is that the user be familiar with the dBase III software.

Data from other utilities can be used for comparison; however, no direct reference should be made to the source utility if any data analysis is published that makes use of data from the database, unless the source utility grants permission for such publication of its data.

11. Interpretation of results

The technical approach to the interpretation of DGA data is to establish the base level of the dissolved gases for a particular system and to monitor changes that take place over time. Part of the interpretation must address the viability of the data and the possibility of sample contamination, usually with air.

11.1 Interpretation of the first round of DGA data

11.1.1 Absolute values

When the first data become available, the gas levels shall be intepreted to determine whether immediate action is required. Table 9 lists the gas levels considered to be typical for HPFF systems of various ages and also lists levels of both moderate and severe concern. These levels have been derived from the ICC Working Group 5-28 database, aided by specific inputs from interested parties. Table 10 provides similar data for low- and medium-pressure SCFF cable systems.

Copyright © 1998 IEEE. All Rights Reserved.

Copyright The Institute of Electrical and Electronics Engineers, Inc.
Provided by IHS under license with IEEE
No reproduction or networking permitted without license from IHS Not for Resale

Table 9—Guidelines for levels of gases found by DGA in HPFF cable systems

Gas	Normal, age in years			Moderate concern	Severe concern
	<5	5–20	>20		
N_2	<120,000			>120 000	>200 000
O_2	500	1000	2000	>3000	>5000
CO_2	300	500	800	>1000	>5000
CO	50	100	200	>500	>1000
H_2	100	300	600	>1000	>5000
CH_4	50	75	100	>500	>1000
C_2H_6	200	300	500	>1000	>1500
C_2H_4	25	50	75	>200	>1000
C_2H_2	0	5	10	>20	>50
TCG	400	750	1200	>3000	>8000

Table 10—Guidelines for levels of gases found by DGA in SCFF cable systems

Gas	Normal, age in years			Moderate concern	Severe concern
	<5	5–20	>20		
N_2	50	75	100	>300	>500
O_2	25	50	70	>100	>300
CO_2	20	50	75	>150	>300
CO	10	20	50	>100	>200
H_2	50	75	100	>200	>400
CH_4	5	15	30	>50	>100
C_2H_6	10	20	40	>75	>150
C_2H_4	0	5	10	>25	>75
C_2H_2	0	0	0	>10	>25
TCG	50	100	200	>400	>800

11.1.2 Key gases

While the diagnostic principles for the interpretation of DGA levels for cable systems have not been fully developed, applying some of the techniques that have evolved for transformer analysis is valuable. One such technique is the consideration of key gases. For cable systems as with transformers, four groups can be separated on the basis of the gases found by DGA.

a) *Low energy discharge in dielectric fluid*. Partial discharge in butt gaps or areas of minor disturbance of the insulating papers will produce a large amount of hydrogen and a small amount of methane. The key gas for this condition is hydrogen.

Copyright © 1998 IEEE. All Rights Reserved.

Copyright The Institute of Electrical and Electronics Engineers, Inc.
Provided by IHS under license with IEEE
No reproduction or networking permitted without license from IHS
Not for Resale

b) *Overheating of cellulose*. If a significant amount of cellulose reaches temperatures above 100 °C for an extended length of time, carbon monoxide and carbon dioxide will be produced, with a small amount of hydrogen. Carbon monoxide is the key gas for the involvement of cellulose.

c) *Overheating of dielectric fluid*. If dielectric fluid has been heated above 200 °C, the amount of ethylene produced will be larger than the other hydrocarbon gases. Ethylene is the key gas for a severe overheating problem, not involving cellulose and not involving arcing.

d) *Arcing in dielectric fluid*. Acetylene is the key gas for a condition that involves arcing between metallic components. The importance of the presence of acetylene warrants further discussion.

Aging studies carried out on fluid/paper insulation at high temperatures (>120 °C) both with and without an applied electric field have shown clearly that small amounts of acetylene gas are produced only in the former case due, presumably, to low-level partial discharge or corona activity. This conclusion is reasonable according to Halstead (Halstead, [B7]), who made a theoretical thermodynamic assessment of the formation of simple gaseous hydrocarbons in mineral fluid. Halstead demonstrated that the relative proportions of these gases would vary with the temperature at the point of decomposition and that each gas would attain its maximum rate of evolution at a different temperature. With reference to acetylene, Halstead concluded that there would be zero evolution at the temperatures associated with normal operation of electrical equipment and also those due to hotspots of purely thermal (ohmic and dielectric loss) origin. In fact, acetylene gas formation should only be expected at extremely high temperatures such as those occurring in electrical discharge or arcing. In consequence, acetylene is only present in trace or minor quantities under normal operating and incipient fault conditions, respectively. Its presence in larger quantities (e.g. >10% of the total combustible gases generated) would indicate that arcing is active or that some type of fault had already taken place.

11.1.3 Gas ratios

Transformer technology has identified several gas ratios to aid in the diagnosis of a transformer's condition. Some are clearly relevant to cable technology but most do not have any basis for correlation with known types of cable problems. Specifically, the Rogers Ratio Method and the Dornenburg Ratio Method, both fully described in IEEE Std C57.104-1991, are not recommended at this time for cable applications because of the lack of experience correlating causes and effects with cable fluids and cable problems. These methods are most useful when diagnosing overheated fluid symptoms caused by magnetic problems in transformers with no ionization and no cellulose involvement, a fault condition that is uncommon in cable systems.

a) CO/CO_2. This ratio, or its inverse, is the classic indicator of the thermal decomposition of cellulose. The ratio increases as the exposure temperature increases since the formation of CO requires more energy than CO_2. When the key gas CO is present, it can be the result of only two phenomena: cellulose decomposition or fluid oxidation. The latter should not occur in a cable system unless the fluid has a high oxygen content, high peroxide content or high water content. If the oxygen content is low and the fluid's power factor at 100 °C is low, then the CO is probably an indication that some part of the cellulose system is operating in the range of 100 °C or higher.

b) CH_4/H_2. This ratio is used to differentiate a condition of mild ionization from one of moderate overheating in the dielectric fluid. In the former case, the CH_4/H_2 ratio will be much less than one; and, in the latter case, it will be greater than one.

c) C_2H_2/TCG. As noted above, if this ratio approaches 10% of the total combustible gas content, significant arcing activity probably exists in the system. Such a condition should warrant immediate attention. One common cause involves sparking of circulating shield currents when isolated sections of shield are close to but not touching parallel paths in the grounding system. Severe TMB damage to the cable shield can also result in a spitting condition at the sharp edges of displaced metallic shielding tapes. This condition will often produce CO in addition to C_2H_2, because the outer paper insulating and carbon black shielding tapes will be involved.

Copyright © 1998 IEEE. All Rights Reserved.

--`,,,`,`-`-`,,`,,`,`,,`---

Copyright The Institute of Electrical and Electronics Engineers, Inc.
Provided by IHS under license with IEEE
No reproduction or networking permitted without license from IHS Not for Resale

d) O_2/N_2. The ratio of oxygen to nitrogen will be approximately 0.5 when air is dissolved in dielectric fluid. Fluids from HPFF systems that use nitrogen as the storage blanketing gas will usually exhibit a ratio much smaller then 0.5, making this ratio irrelevant. However, for conditions where the nitrogen level should be very low, as in SCFF cables, a ratio near 0.5 may indicate air contamination in the sample or in the cable system.

11.1.4 System operating history

Cable systems operating under normal conditions should have low dissolved combustible gas contents. However, it is possible to find gas levels on a cable system that may be over the limitations suggested in Table 9 or Table 10 and such levels should be a cause for concern. Those gases may have inadvertently been introduced into the system during installation or remained in the cable system from past failures, cable problems, or maintenance work. Access to the past operating history of the cable system is essential to determine whether past events may be the cause for present high levels.

Electrical stress and thermal stress are the two principal factors causing the formation of gases from the insulating tapes and the fluid. For proper interpretation of the gas samples, factors such as the record of failures on the cables, splices, and terminations; TMB history; loading conditions; hot spots along the feeder route; and fluid leaks should be included in the analyses.

11.2 Changes in dissolved gas concentrations with time

With initial gas levels established, tracking gas contents over time is possible. One potential problem is the fact that the gas levels in the fluid may be dependent on the thermal state of the cable system at the time the sample is removed. H_2O, CO, and CO_2 are soluble in cellulose and the temperature of the cellulose-fluid interface will influence the partition of these gases between the two. Thus, obtaining gas data in winter and summer for a few years is recommended to observe any cyclic tendency before reaching a conclusion on whether seasonal differences are present.

The loading history may also be relevant to changes in gas concentrations. If the circuit load has reached emergency levels for as little as a few hours or sustained heavy loading near the circuit rating has been experienced, one should expect to see an increase in gas levels, given sufficient time for the gases to distribute into the fluid that reaches the sampling port.

At present, data are insufficient to quantify meaningful rates of change. The first step is to establish trends for each gas. A dramatic change from an established trend should prompt further investigation into the recent operation of the circuit and perhaps a retest or an increase in the DGA sampling frequency.

12. Methods for treatment of systems with high gas content

Cables systems can be treated to remove dissolved gases and other contaminants that might impair the dielectric function of the cable insulation. However, a pipe cable system that uses a nitrogen blanket in the fluid storage tanks is unlikely to reach a total gas content that is not dominated by the nitrogen content. The more likely scenario favoring a fluid treatment process is to reduce a fluid's power factor or to remove a relatively high concentration of combustible gases so that the gas generation rates can be tracked and perhaps localized.

The gas removal process requires the exposure of the dielectric fluid to vacuum. This process is done in specially built degassing systems, which are available from several sources. It is common for a degassing system to also contain fluid filters that can be equipped with a passive filtering medium such as paper or a chemically active medium such as Fuller's Earth, which is able to remove the ionic contaminants that cause high power factor of the fluid. Degassing equipment is usually trailer mounted, but permanent installation is possible and may be indicated, especially where large amounts of fluid are involved, or several circuits may be hydraulically interconnected.

Copyright © 1998 IEEE. All Rights Reserved.

Copyright The Institute of Electrical and Electronics Engineers, Inc.
Provided by IHS under license with IEEE
No reproduction or networking permitted without license from IHS Not for Resale

The treatment process follows logical guidelines. The goal is to treat all of the fluid in the system without mixing or contaminating treated fluid with untreated fluid, but this goal may not always be practical. The very long diffusion times for gases give rise to some flexibility in the design of the logistics to suit a particular situation. If properly designed, fluid treatment can be done while the circuit is in service. However, safety concerns more often dictate that the circuit be de-energized.

12.1 Treating circulated pipe cable systems

Pipe cable systems with fluid circulation capability can be treated in two ways: in bypass mode or in the series mode. In either case, the pressurization system must be operational, and the degasser must have inlet and outlet pressure capabilities consistent with the operating pressures in the system.

12.1.1 Bypass mode

With circulation on, a degasser can be connected at any point in the loop to degas and filter the fluid as long as two access valves are available that are not side-by-side. An example of a typical arrangement could use the top and bottom valves on a joint casing or the access valves on the trifurcator of each feeder. The throughput of the degasser should be less than 75% of the circulation flow rate. This method will generally require the equivalent of two to three passes through the degasser, that is, the degassing time will be two to three times the time it takes for the degasser to treat the total volume of the circulated loop.

12.1.2 Series mode

An alternate to the bypass mode has the degasser connected as the source of the circulation, usually at one end. The degasser draws its inlet fluid from one feeder and pumps its treated fluid into the other feeder. Variations of this method allow the degasser to be connected between the two feeders at any manhole and circulate to any other manhole by adding cross-over piping or to one end by closing the cross-over valve at the other end. The series method is usually quicker, achieving good results with less than twice the system volume throughput.

12.2 Treating static pipe cable systems

Most single-circuit pipe cable systems do not have a return pipe that would enable a circulating mode of treatment. These systems must be treated in a batch mode utilizing some form of fluid transport that will be dictated by the equipment available. If the degasser has a relatively small storage capability, two tank trucks can be used. One full tank truck acts as the source of fluid to the degasser while the other empty tank truck is positioned along the feeder. The degasser output pumps treated fluid into the feeder toward the remote truck, which is connected to the feeder with a pressure control valve. When the remote tanker is full the process is stopped while the two trucks exchange positions. Pressure control must be carefully coordinated to avoid loss of pressure at any point on the feeder.

12.3 Treating SCFF cable systems

SCFF cable systems can be treated with the same principles used for pipe cable systems, except the control of pressure at all parts of the system during the entire process is far more critical because of the increased risk of forming a gas bubble that could be fatal. Also, the tolerable total gas content is much lower, typically around 1% (10 000 ppm). SCFF cables are best treated one hydraulic section at a time, treating the cable and accessories separately from the fluid in the pressure control reservoirs. The detailed procedures for dealing with pressure control apparatus for SCFF cable systems are complex and beyond the scope of this guide.

Copyright © 1998 IEEE. All Rights Reserved.

Copyright The Institute of Electrical and Electronics Engineers, Inc.
Provided by IHS under license with IEEE
No reproduction or networking permitted without license from IHS Not for Resale

13. The ICC database

13.1 Database software

In 1984, a database was established by ICC Working Group 5-28. The dBase III database management software for the IBM DOS-based PC was chosen for this database. The existing ICC Working Group 5-28 database and continuing updates are available from the Chairperson of the ICC Working Group 5-28. The dBase III Software is a product of the Ashton-Tate Company and later versions are available at most computer software stores and mail-order outlets.

For the purposes of consistency and sharing of data, the format of Forms 1 and 2 (see Clause 10) should be adopted and the dBase III database management software used for archiving data. Most spreadsheets provide the capability to import dBase III data into their own format, and vice versa. Therefore, if one is more comfortable in another database, it can be used and its data can still be appended to the ICC Working Group 5-28 database. The dBase III spreadsheet can also output its data in universal ASCII format, which can be loaded into most spreadsheets. The Chairperson can provide advice on the choice of database and can perform translations if requested.

The dBase III format consists of two files of data that are connected by the record number of each data set. The first file is the descriptive file that corresponds to Reporting Form #1, Cable System Description (see Figure 6). The dBase III descriptive files use the file name convention "xxxxDSCR.DBF" where "xxxx" names the particular database: HPFF for pipe cable systems and SCFF for self-contained systems. The file format consists of 13 columns of information and does not include all of the data on Form #1 because the reporting forms have been upgraded since the creation of the dBase III database in 1984. The column headers and data for the descriptive file are shown in Figure 8, using a 4.5 point font to fit the format to the page.



Figure 8—Format of dBase III descriptive file

The second file contains the DGA data and corresponds to Reporting Form #2, Gas Analysis Data (see Figure 7). This file format consists of 15 columns of data including each record number that connects the data line to the descriptive file record's line defined above. Figure 9 illustrates the format of this data in the dBase III spreadsheet. In this example, all gas contents have been expressed in ppm.



Figure 9—Format of dBase III DGA data file

As of January 1997, 921 records of data are in the HPFF data file and 204 records of data in the SCFF data file, donated by 22 utility users. Approximately 1500 additional records of data have been donated, but not yet entered into the dBase III database.

Copyright © 1998 IEEE. All Rights Reserved.

Copyright The Institute of Electrical and Electronics Engineers, Inc.
Provided by IHS under license with IEEE
No reproduction or networking permitted without license from IHS
Not for Resale

14. Bibliography

[B1] ASTM D2298 (Discontinued 1987), Standard Test Method for Stability of Insulating Oils Under Electrical Stress (Merrell Test).

[B2] ASTM D2300-85(1991)e1, Standard Test Method for Gassing of Insulating Oils Under Electrical Stress and Ionization (Modified Pirelli Method).

[B3] Bartnikas, R., and Srivastava, K. D., *Elements of Cable Engineering,* Sanford Educational Press, Waterloo, Ontario, 1980.

[B4] Clark, F. M., "Pyrochemical Behavior of Cellulose Insulation," *A.I.E.E. Electrical Engineering,* pp. 1088–1094, Oct. 1935.

[B5] EPRI EL-7488-L, "Development of an Oil Deterioration Test Method to Monitor the Condition of High-Pressure Fluid-Filled Paper Cable," Project 7895-1, Nov. 1991.

[B6] Flowers, L. C., "Moisture Evolution Rates Calculated for Cellulose Paper Undergoing Thermal Decomposition," *Insulation,* pp. 23–26, Sept. 1964.

[B7] Halstead, W. D., "A Thermodynamic Assessment of the Formation of Gaseous Hydrocarbons in Faulty Transformers," *Journal of the Petroleum Institute,* Vol. 59, Sept. 1973.

[B8] Head, J. G., et al., "Aging of Oil Filled Cable Insulation." CIGRE Paper No. 15-07, Plenary Session, Paris, 1982.

[B9] Hiro, T., and Suganuma, T., "Rapid Measurement of the Deterioration of Oil-Immersed Paper," *IEEE Transactions on Electrical Insulation,* EI-7, pp. 122–126, 1972.

[B10] ICC Minutes, Spring Meeting, 1995.

[B11] Karger, B., et al., *An Introduction to Separation Science,* New York: John Wiley & Sons, 1973.

[B12] Lawson, W. G., et al., "Thermal Aging of Cellulose Paper Insulation," *IEEE Transactions on Electrical Insulation,* EI-12, pp. 61–66, 1977.

[B13] Lyke, A., "Power Transformer Dissolved Gas Analysis," General Electric Bulletin GET-6552, Pittsfield, MA, Dec. 1977.

[B14] Murphy, E. J., "Gases Evolved by the Thermal Decomposition of Paper," *Transactions Electrochemical Society,* Vol. 83, p. 161, 1943.

[B15] Murphy, E. J., "Thermal Decomposition of Natural Cellulose in Vacuo," *Journal of Polymer Science,* Vol. 58, pp. 649–665, 1962.

Copyright © 1998 IEEE. All Rights Reserved.

Copyright The Institute of Electrical and Electronics Engineers, Inc.
Provided by IHS under license with IEEE
No reproduction or networking permitted without license from IHS Not for Resale

Annex A

(informative)

DGA Reporting forms

Reporting Form #1—Cable System Description

This form is used to describe a particular circuit on a utility system that should be submitted only once, unless an historical update is required.

UTILITY_____
Circuit Designation_____

Nominal Voltage_____
Cable Type_____
Circuit Length_____
Number of Joints_____
Year of Installation_____

CABLE DETAILS_____
Cond. Size_____
Cond. Material_____
Ins. Thick_____
Impreg. Type_____
Manufacturer(s)_____
Skid Wire Mat'l_____

PIPE DETAILS_____
Size_____
Internal Coating_____
Filling Fluid_____
Approx. Quantity_____

OPERATING DETAILS_____
Storage Tank Gas Pressure & Gas Type_____
Fluid Circulation_____
Max. Oper. Pressure_____
Min. Oper. Pressure_____
Elevation Difference—Pothead to Pumping Plant_____
Elevation Difference—Max. Pipe Elev. to Pumping Plant_____

CABLE HISTORY_____
Faults in System?_____
Leaks?_____
Accidental Pressure Loss?_____
Welding on Fluid-Filled Pipe or Pipe Casings?_____
Welding on Drained Pipe or Pipe Casings?_____
Filling Fluid Changes?_____
Circuit Modifications?_____

BRIEF DESCRIPTION:_____
_____
_____
_____
_____
_____

Copyright © 1998 IEEE. All Rights Reserved.

Copyright The Institute of Electrical and Electronics Engineers, Inc.
Provided by IHS under license with IEEE
No reproduction or networking permitted without license from IHS
Not for Resale

Reporting Form #2—Gas Analysis Data

UTILITY_____ **CIRCUIT DESIGNATION**_____

FLUID SAMPLE DATA

Sample Number	**1**	**2**	**3**	**4**	**5**	**6**
Identification						
Location						
Size						
Container Type						
Sample Time						
Sample Date						
Test Date						

GAS-IN-FLUID DATE—% OF FLUID VOLUME OR PPM BY VOLUME

Nitrogen %						
Oxygen %						
CO_2—ppm						
CO—ppm						
Hydrogen—ppm						
Methane—ppm						
Ethane—ppm						
Ethylene—ppm						
Acetylene—ppm						
Other Hydrocarbons						
Total Combustible Gas—ppm						
Total Gas %						

Copyright © 1998 IEEE. All Rights Reserved.

Copyright The Institute of Electrical and Electronics Engineers, Inc.
Provided by IHS under license with IEEE
No reproduction or networking permitted without license from IHS
Not for Resale