



COMMONWEALTH OF PENNSYLVANIA
PENNSYLVANIA PUBLIC UTILITY COMMISSION
COMMONWEALTH KEYSTONE BUILDING
400 NORTH STREET, HARRISBURG, PA 17120

BUREAU OF
INVESTIGATION
&
ENFORCEMENT

May 13, 2026

Via Electronic Filing

Matthew L. Homsher, Secretary
Pennsylvania Public Utility Commission
Commonwealth Keystone Building
400 North Street
Harrisburg, PA 17120

Re: Pennsylvania Public Utility Commission,
Bureau of Investigation and Enforcement v.
FirstEnergy Pennsylvania Electric Company
Docket No. C-2026-
Formal Complaint (Non-Proprietary and Proprietary Version)

Dear Secretary Homsher:

Enclosed for electronic filing is the **Non-Proprietary** version of the **Formal Complaint** of the Bureau of Investigation and Enforcement (“I&E”) of the Pennsylvania Public Utility Commission in the above-referenced matter. The **Proprietary** version has been submitted to the Secretary’s Bureau via their ShareFile.

Copies have been served on the parties of record in accordance with the Certificate of Service. If you have any questions, please do not hesitate to contact me.

Sincerely,

A handwritten signature in blue ink, appearing to read 'Colby B. Widdowson', is written over a light blue circular stamp.

Colby B. Widdowson
Prosecutor
Bureau of Investigation and Enforcement
PA Attorney ID No. 326185
(717) 787-2139
cwiddowson@pa.gov

CBW/ac
Enclosures

cc: Per Certificate of Service
Robert Horensky, Manager, Safety Division (*via email – rhorensky@pa.gov*)
Brent Killian, Supervisor, Electric Safety Division (*via email – bkillian@pa.gov*)
Don Trumpie, Engineer, Electric Safety Division (*via email – dtrumpie@pa.gov*)

NOTICE

A. You must file an Answer within 20 days of the date of service of this Complaint.

The date of service is the mailing date as indicated at the top of the Secretarial Letter. *See* 52 Pa. Code § 1.56(a). The Answer must raise all factual and legal arguments that you wish to claim in your defense, include the docket number of this Complaint, and be verified. The Answer must be submitted by efilng with the Secretary of the Commission by opening an efilng account through the Commission's website and accepting eservice at <http://www.puc.state.pa.us/efiling/default.aspx>. If your filing contains confidential material, you are required to file by overnight delivery to ensure the timely filing of your submission to:

Matthew L. Homsher, Secretary
Pennsylvania Public Utility Commission
Commonwealth Keystone Building
400 North Street
Harrisburg, PA 17120

If your Answer is 250 pages or less, you are not required to file a paper copy. If your Answer exceeds 250 pages, you must file a paper copy with the Secretary's Bureau.

Additionally, please electronically serve a copy on:

Colby B. Widdowson, Prosecutor
Pennsylvania Public Utility Commission
Bureau of Investigation and Enforcement
cwiddowson@pa.gov

B. If you fail to Answer this Complaint within 20 days, the Bureau of Investigation and Enforcement will request that the Commission issue an Order imposing the requested relief.

C. You may elect not to contest this Complaint by paying the civil penalty and performing the requested relief within 20 days. Send only a certified check or money order made payable to the "Commonwealth of Pennsylvania," with the docket number indicated, and mailed to:

Matthew L. Homsher, Secretary
Pennsylvania Public Utility Commission
Commonwealth Keystone Building
400 North Street
Harrisburg, PA 17120

D. If you file an Answer which either admits or fails to deny the allegations of the Complaint, the Bureau of Investigation and Enforcement will request that the Commission issue an Order imposing the requested relief set forth in this Complaint.

E. If you file an Answer which contests the Complaint, the matter will be assigned to an Administrative Law Judge for hearing and decision. The Judge is not bound by the penalty set forth in the Complaint and may impose additional and/or alternative penalties as appropriate.

F. If you are a corporation, you must be represented by legal counsel. *See* 52 Pa. Code § 1.21.

G. Alternative formats of this material are available for persons with disabilities by contacting the Commission's ADA Coordinator at 717-787-8714.

**BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION**

Pennsylvania Public Utility Commission,	:	
Bureau of Investigation and Enforcement,	:	
Complainant	:	
	:	
v.	:	Docket No. C-2026-
	:	
FirstEnergy Pennsylvania Electric Company,	:	
Respondent	:	

**FORMAL COMPLAINT
(NON-PROPRIETARY VERSION)**

NOW COMES the Bureau of Investigation and Enforcement (“I&E”) of the Pennsylvania Public Utility Commission, by its prosecuting attorneys, pursuant to Section 701 of the Public Utility Code, 66 Pa.C.S. § 701, and files this Formal Complaint (“Complaint”) against FirstEnergy Pennsylvania Electric Company (“FirstEnergy” or “Respondent”) alleging violations of the Public Utility Code and the Public Utility Commission’s Regulations in connection with a transformer failure on August 27, 2023 at the FirstEnergy’s Bradford West substation in Bradford, PA. In support of its Complaint, I&E respectfully avers as follows:

I. COMMISSION JURISDICTION AND AUTHORITY

1. The Pennsylvania Public Utility Commission (“Commission” or “PUC”), with a mailing address of the Commonwealth Keystone Building, 400 North Street, Harrisburg, PA 17120, is a duly constituted agency of the Commonwealth of Pennsylvania empowered to

regulate public utilities within the Commonwealth pursuant to the Public Utility Code, 66 Pa.C.S. §§ 101, *et seq.* (“Code”).

2. Complainant is the Commission’s Bureau of Investigation and Enforcement, which is the bureau established to take enforcement actions against public utilities and other entities subject to the Commission’s jurisdiction pursuant to 66 Pa.C.S. § 308.2(a)(11); *See also Implementation of Act 129 of 2008; Organization of Bureaus and Offices*, Docket No. M-2008-2071852 (August 11, 2011) (delegating authority to initiate proceedings that are prosecutory in nature to I&E).

3. Complainant’s prosecuting attorney is as follows:

Colby B. Widdowson
Prosecutor
cwiddowson@pa.gov
(717) 787-2139

Stephanie M. Wimer
Deputy Chief Prosecutor
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Pennsylvania Public Utility Commission
Bureau of Investigation and Enforcement
Commonwealth Keystone Building
400 North Street
Harrisburg, PA 17120

4. Respondent is FirstEnergy Pennsylvania Electric Company with a principal place of business and mailing address of 2800 Pottsville Pike, Reading, PA 16001.

5. Section 501(a) of the Code, 66 Pa.C.S. § 501(a), authorizes and obligates the Commission to execute and enforce the provisions of the Code.

6. Section 701 of the Code, 66 Pa.C.S. § 701, authorizes the Commission, *inter alia*, to hear and determine complaints against public utilities for violations of any law or

regulation that the Commission has jurisdiction to administer or enforce.

7. Section 2804(1)(ii) of the Public Utility Code, 66 Pa.C.S. § 2804(1)(ii), requires the Commission “to ensure the continuation of safe and reliable electric service to all consumers in the Commonwealth, including . . . [t]he installation and maintenance of transmission and distribution facilities in conformity with established industry standards and practices, including the standards set forth in the National Electric Safety Code [(“NESC”).” See also 52 Pa. Code §§ 57.193-194.

8. Respondent is a “public utility” as that term is defined at 66 Pa.C.S. § 102,¹ as it is engaged in providing public utility service as an electric distribution company (“EDC”) in the Commonwealth of Pennsylvania to the public for compensation with a utility code number of 1126015.

9. Section 3301 of the Public Utility Code, 66 Pa.C.S. § 3301, authorizes the Commission to impose civil penalties on any public utility or any other person or corporation subject to the Commission's authority for violation(s) of the Public Utility Code and/or Commission regulations. Section 3301(a)-(b) of the Public Utility Code, 66 Pa.C.S. § 3301(a)-(b), allows for the imposition of a separate civil penalty for each violation and each day’s continuance of such violation(s).

10. Respondent, in providing electric distribution service to the public for compensation, is subject to the power and authority of this Commission pursuant to Section

¹ “Public utility” is defined as:

- (1) Any person or corporations now or hereafter owning or operating in this Commonwealth equipment or facilities for:
 - (i) Producing, generating, transmitting, distributing or furnishing natural or artificial gas, electricity, or steam for the production of light, heat, or power to or for the public for compensation.
- 66 Pa.C.S. § 102.

501(c) of the Code, 66 Pa.C.S. § 501(c), which requires a public utility to comply with Commission regulations and orders.

11. Pursuant to the provisions of the applicable Commonwealth statutes and regulations, the Commission has jurisdiction over the subject matter and the actions of Respondent related thereto.

II. BACKGROUND

12. On December 7, 2023, the Commission issued an Order approving the merger of a number of Pennsylvania electric distribution companies, including Pennsylvania Electric Company (“Penelec”), into a single entity FirstEnergy Pennsylvania Electric Company.²

13. Prior to December 7, 2023, Penelec was a “public utility” as that term is defined at 66 Pa.C.S. § 102, as it was engaged in providing public utility service as an EDC in the Commonwealth of Pennsylvania to the public for compensation.

14. The conduct underlying this Formal Complaint occurred in Penelec’s electric distribution system, prior to the Commission’s Order approving the merger.

15. On January 9, 2024, State Representative Martin Causer (“Representative Causer”), of the 67th Legislative District, submitted a letter to the Commission, on behalf of his constituents, alleging reliability and service issues with the electric service provided by Penelec in the Bradford, PA service area in 2023. The letter appended a list of complaints from customers who contacted Representative Causer’s Office.

16. The Bureau of Investigation and Enforcement’s Electric Safety Division

² See *Joint Application of Metropolitan-Edison Company, et. al.*, Docket Nos. A-2023-3038771, A-2023-3038792, A-2023-3038793, A-2023-3038794, A-2023-3038795, A-2023-3038807, A-2023-3038808, G-2023-3038818, G-2023-3038819, G-2023-3038820, G-2023-3038821, and G-00020956 (Order entered December 7, 2023).

(“Electric Safety”) conducted an extensive investigation of the allegations submitted by Representative Causer.

17. Electric Safety’s investigation involved multiple in person investigations of Respondent’s distribution system and numerous data requests between February 26, 2024 and November 14, 2025.

A. 2023 Damage Claims

18. In response to a Data Request, Respondent indicated that they received the following electric damage claims from customers in calendar year 2023:

- a. 10 claims received for a storm event that occurred on March 25, 2023;
- b. 1 claim received for a voltage complaint on May 26, 2023;
- c. 1 claim received for a momentary outage on July 17, 2023;
- d. 3 claims received for an outage event on August 27, 2023;
- e. 5 claims received for an outage event on September 5, 2023;
- f. 44 claims received for an outage event on December 3, 2023.

19. In response to a Data Request, Respondent provided the following explanations for each of the above events, respectively:

- a. On March 25, 2023, a major wind event occurred, resulting in three broken poles due to a downed tree;
- b. On May 26, 2023, a Penelec Troublemaker determined that the premise recorded high voltage and had a bad neutral wire;
- c. On July 17, 2023, a momentary outage caused by a car accident impacted a pole that occurred close to the customer’s residence;
- d. On August 27, 2023, crews located a broken spacer on the 12 kilovolt (“kV”) line; the spacer is used to separate phase wires. Problems were detected with the transformer at the Bradford West Substation and the transformer was isolated;

- e. On September 5, 2023, an outage occurred from overloading the recloser at the Mill Street Substation due to the transformer isolation at the Bradford West Substation from the August 27 event. A high load due to the warm temperatures on the Labor Day weekend caused the overload condition. The exit cable leaving the Mill Street Substation was damaged and had to be replaced; and
- f. On December 3, 2023, a large tree limb from an off-Right-of-Way tree came down across the 34.5 kV and 8.32 kV lines between poles H-17-28 and H-17-29, causing an outage. The tree brought the 34.5 kV line into the 8.32 kV line at that location. There was no damage to the 34.5 kV line.

20. In response to a Data Request, Respondent provided the following description of actions taken to mitigate the damage related to the above identified events, respectively:

- a. On March 25, 2023, crews made repairs and replaced poles.
- b. On May 26, 2023, Penelec Troubleman repaired the neutral and replaced all connections and the service wire on the day the trouble ticket was created.
- c. On July 17, 2023, crews made repairs due to the car/pole accident.
- d. On August 27, 2023, actions taken for restorations included isolating the failing transformer and setting up a mobile transformer at the substation. The line spacer issue was repaired. The normal load fed from the Bradford West Substation was being supplied from surrounding sources. The mobile transformer had been delivered to the Bradford West Substation prior to Labor Day and the transformer was being tested and readied for in service, but was not installed at this time;
- e. During the September 5, 2023 event, crews replaced the failed cable at Mill Street and installed the mobile transformer at the Bradford West Substation, working simultaneously. The exit cable leaving the Mill Street Substation was replaced. There were parallel paths to restore customers; and
- f. On December 3, 2023, a new piece of wire had to be sleeved into the damaged 8 kV line as well as repairing the neutral that came down.

21. Upon further investigation into the above identified events, Electric Safety was unable to substantiate Respondent's investigation results and explanation for the August 27,

2023 transformer failure at the Bradford West Substation and the resulting September 5, 2023 overloading of the recloser at the Mill Street Substation due to the transformer isolation at the Bradford West Substation.

22. Respondent received claims from seven (7) customers³ for damages as a result of the August 27, 2023 transformer failure at the Bradford West Substation and the resulting September 5, 2023 overloading of the recloser at the Mill Street Substation. See I&E Exhibit 1 (**Confidential**).

23. Respondent denied the claims from those seven (7) customers alleging that:

Our investigative regional report reveals that the incident you experienced was the result of extreme heat paired with a corresponding high electricity demand. This was exacerbated by an ongoing repair to a non-preventable, sudden, and unforeseen transformer failure in your area on 8/27/2023. These factors together caused voltage variations and the outage. As a result of the investigation conducted in this matter, there is no evidence of any improper conduct on the part of Penelec or its employees.

And

Our investigative regional personnel report reveals that the incident you experienced was the result of a non-preventable, sudden, and unforeseen transformer failure at the substation that feeds your home.

See attached I&E Exhibit 2 (**Confidential**).

24. In denying the customer claims, Respondent cited Section 21 of its Electric Service Tariff, which states that:

The Company shall not be liable for any damages due to accident, strike, storm, lightning, riot, fire, flood, legal process, state or municipal interference, or any other cause beyond the Company's control. In all other circumstances, unless caused by the willful and/or wanton misconduct of the Company, the liability of the Company to Customers or third parties for all

³ One customer submitted two claims for the August 27, 2023 transformer event.

injuries and damages, direct or consequential, including damage to computers and other electronic equipment and appliances, or loss of business, profit or production caused by variations or interruptions in electric supply, high or low voltage, spikes, surges, single phasing, phase failure or reversal, stray voltage, neutral to earth voltage, equipment failure or malfunction, response time to electric outages or emergencies, or the non-functioning or malfunctioning of street lights or traffic control signals and devices shall be limited to Five Hundred Dollars (\$500) for residential customers and Two Thousand Dollars (\$2,000) for commercial and industrial customers.

B. August 27, 2023 Transformer Failure

25. The transformer that failed on August 27, 2023, located at the Bradford West Substation, was manufactured in 1971 by Westinghouse with a rectangular core (“Failed Transformer”).

26. The Failed Transformer had a top name plate rating of 5,600kVA.

27. As part of the routine maintenance and inspections of its substations, Respondent conducts oil sampling of the transformers at those substations.

28. On May 3, 2023, an oil sample taken from the Failed Transformer was sent to Delta-X Research (“Delta-X”) for analysis.

29. As part of the oil sample testing, Delta-X Research conducted a dissolved gas analysis (“DGA”).

30. DGA is the identification, measurement, and interpretation of the gases dissolved in the insulating liquid in a transformer. DGA tests for gases that are formed in a transformer when an electrical fault or other abnormal conditions exist within the transformer. These gases include hydrogen (H₂), methane (CH₄), ethylene (C₂H₄), acetylene (C₂H₂), carbon monoxide (CO), and carbon dioxide (CO₂). See attached I&E Exhibit 3.

31. The purpose of DGA is to detect and identify faults and improve safety and reliability through improved awareness of transformer condition and early detection of faults. See attached I&E Exhibit 3.

32. Delta-X uses the DGA to create a reliability based dissolved gas analysis report that gives insight into the status of the transformer by analyzing the entire DGA history and by comparing it with statistical models of similar transformers.

33. Delta-X provided Respondent with a DGA report for the May 3, 2023 oil sample (“May 2023 Report”). See attached I&E Exhibit 4.

34. A true and correct copy of Delta-X’s “Reliability-based DGA Quick Start Guide” is attached as I&E Exhibit 5.

35. The May 2023 Report provided to Respondent indicated that the Failed Transformer’s gassing status score changed from a 1 to a 4, with 1 indicating satisfactory operation and no gassing ever and 4 indicating that current extreme fault gas production and continued operation could result in transformer failure. See attached I&E Exhibits 4 and I&E Exhibit 5.

36. The May 2023 Report indicated the following sharp jumps, abnormal levels, and abnormal increments in the dissolved gasses in the May 3, 2023 oil sample:

- a. Hydrogen (H₂) increased to 202 μL/L⁴ from 0 μL/L;
- b. Methane (CH₄) increased to 992 μL/L from 1 μL/L;
- c. Ethane (C₂H₆) increased to 324 μL/L from 2 μL/L;
- d. Ethylene (C₂H₄) increased to 2064 μL/L from 6 μL/L; and

⁴ μL/L represents microliter per liter in the measurements of volume. μL is a microliter and is equal to 0.000001 liters.

- e. Acetylene (C₂H₂) increased to 25 µL/L from 0 µL/L.

See attached I&E Exhibit 4.

37. The May 2023 Report diagnosed a T3 thermal fault above 700 degrees Celsius inside the transformer and directed that investigative sampling should be considered. See attached I&E Exhibit 4.

38. A thermal fault in a transformer is the presence of excessive heat or overheating caused by overloading, cooling system failures, poor connections, and stray currents.

39. After the receipt of the May 2023 Report, Respondent did not conduct further investigative oil sampling of the Failed Transformer, investigate the Failed Transformer, or perform maintenance on the Failed Transformer prior to the August 27, 2023 failure.

40. During the summer of 2023, the University of Pittsburgh at Bradford opened a new building on campus.

41. In response to a I&E Data Request, Respondent indicated that the area served by the Failed Transformer was growing at 1% per year and had a recent load addition of 600kVA from the University of Pittsburgh at Bradford campus.

42. Respondent ran the Failed Transformer until it failed on August 27, 2023.

43. One hundred and sixteen (116) days elapsed between the May 3, 2023 oil sample and the failure on August 27, 2023.

44. The load at the time of failure on August 27, 2023 is not known.

45. The failure of the transformer caused customer outages and surges.

46. Respondent responded to the transformer failure by sending power via three different circuits including Corydon Street Circuit 00106-42 at Bradford South Substation,

South Avenue Circuit 00107-42 at Bradford South Substation and at Jackson Avenue Circuit 00142-42 at Bradford Mill Street Substation.

47. On September 5th, 2023, another failure, this time underground cables at the Bradford Mill Street substation, occurred causing additional customer outages and surges.

48. The failure at the Mill Street Substation resulted from routing power through the substation as a temporary fix to the August 27, 2023 transformer failure.

49. In response to these incidents, Respondent temporarily installed a mobile transformer at the Bradford West substation and repaired the failed cables at the Bradford Mill Street substation.

50. The mobile transformer at Bradford West Substation measured a load of 5,227kVA.

51. The total number of customers affected by the power outage on August 27, 2023 is 1,617, broken down by circuit as follows:

- a. On circuit 00110-42, a total of 228 customers lost power, that include 171 customers for 12 hours and 57 customers for 5 hours and 32 minutes;
- b. On circuit 00111-42, a total of 297 customers lost power for a total of 5 hours and 31 minutes;
- c. On circuit 00112-42, a total of 237 customers lost power, including 119 customers for 12 hours and 24 minutes, 59 customers for 5 hours 32 minutes, and 59 customers for 3 hours and 12 minutes; and
- d. On circuit 00113-42, a total of 855 customers lost power, that include 427 customers for 12 hours and 51 minutes, 214 customers for 5 hours and 32 minutes, and 214 customers for 2 hours and 49 minutes.

52. The total number of customers affected by the power outage on September 5, 2023 is 913, broken down by circuit as follows:

- a. On circuit 00110-42 a total of 170 customers lost power for 4 hours and 59 minutes;
- b. On circuit 00112-42, a total of 101 customers lost power for 25 minutes; and
- c. On circuit 00113-42, a total of 642 customers lost power, including 522 customers for 15 hours and 30 minutes and 120 customers for 15 hours and 16 minutes.

53. The Failed Transformer was replaced with a transformer that had significantly larger capacity, 10,500kVA.

C. Investigation

54. On August 28, 2023, Respondent took an oil sample from the Failed Transformer and sent it to Delta-X for analysis.

55. Delta-X provided Respondent with a DGA report for the August 28, 2023 oil sample (“August 2023 Report”). See attached I&E Exhibit 6.

56. The August 2023 Report provided to Respondent indicated that the Failed Transformer’s gassing status score remained at a 4 from the May 2023 Report. See attached I&E Exhibits 5 and 6.

57. The August 2023 Report indicated the following sharp jumps, abnormal levels, and abnormal increments in the dissolved gasses in the August 28, 2023 oil sample:

- a. Hydrogen (H₂) increased to 3966 µL/L from 202 µL/L;
- b. Methane (CH₄) increased to 2245 µL/L from 992 µL/L;
- c. Ethane (C₂H₆) increased to 599 µL/L from 324 µL/L;
- d. Ethylene (C₂H₄) increased to 5737 µL/L from 2064 µL/L; and
- e. Acetylene (C₂H₂) increased to 10550 µL/L from 25 µL/L.

See attached I&E Exhibit 6.

58. The August 2023 Report diagnosed a D2 high energy arcing discharge inside the transformer and directed that investigative sampling should be considered. See attached I&E Exhibit 6.

59. In response to a data request asking Respondent to “[p]rovide copies of records or reports identifying the maximum power rating, taking age into consideration, for the failed transformer,” Respondent provided the following:

The Bradford West #1 transformer was manufactured in 1971 and was rated at 5,600 kilovolt-amperes (“kVA”). The transformer has a 65-degree rise, which yields 112% top rating of 6,272 kVA. The top rating of 125% of this name plate yields a rating of 7,840 kVA.

60. In response to data request, Respondent identified the Failed Transformer as having a rectangular core. See attached I&E Exhibit 7.

61. Respondent uses section 5.2 of FirstEnergy Distribution System Planning Criteria for the calculation of maximum power rating. See attached I&E Exhibit 8.

(Confidential).

START CONFIDENTIAL

[REDACTED]

END CONFIDENTIAL

III. FIRSTENERGY PROCEDURES

63. In completing its investigation, Electric Safety reviewed FirstEnergy’s policies and procedures as they related to transformer maintenance.

64. Respondent follows the practice and industry standards for maintenance of transformers found at The Institute of Electrical and Electronics Engineers' ("IEEE") "Maintenance of Insulating Mineral Oil in Electrical Equipment" ("IEEE C57-106-2015") and IEEE "Guide for the Interpretation of Gases Generated in Mineral Oil-Immersed Transformers" ("IEEE Std. C57.104-2019").

65. IEEE Std. C57.104-2019 directs that it is important to establish the following priorities when interpreting DGA data:

- a. "Detection: Detect the generation of any gases that exceed "normal" quantities and utilize appropriate guidelines, so the possible abnormality may be recognized- at the earliest possible time to minimize damage or avoid a failure. If this analysis concludes that a fault exists, then proceed with evaluation."
- b. "Evaluation: Evaluate the impact of an abnormality on the serviceability of the transformer, using a set of guidelines or recommendations. Expert opinion, operator experience, and unit specific conditions should be part of the evaluation."
- c. "Action: Take the recommended action, beginning with increased surveillance and confirming or supplementary analysis. For example, if a thermal fault is suspected, which may be load sensitive, load reduction (if possible) may help with the diagnosis. If it is not possible, then alternatives, as drastic as removal of the unit from service, may need to be considered."

See attached I&E Exhibit 3.

66. IEEE Std. C57.104-2019 directs that when high gas levels or continuing significant gas production is detected, mitigative action or other responses should be considered. See attached I&E Exhibit 3.

67. IEEE Std. C57.104-2019 directs that if there is an indication of high-energy arcing (D2) or a high-temperature thermal fault (T3) another analysis may be prudent and fault diagnostic and DGA surveillance protocol are warranted. See attached I&E Exhibit 3.

68. IEEE Std. C57.104-2019 instructs that “[i]f abnormal DGA results are found, any available supplementary information, such as test and maintenance records, load data, environmental conditions, etc., should be consulted for possible clues as to the origin and nature of the abnormalities.” See attached I&E Exhibit 3.

69. In the cases of “extreme DGA results,” IEEE Std. C57.104-2019 instructs that large changes in gas levels “warrant immediate extra investigation, which may include additional oil analysis and physical or electrical testing,” for example, “if an increase in C₂H₄ of 200 [ppm] or a level of C₂H₆ of 1000 [ppm] is observed, these would be considered extreme.” “In such cases, immediate investigation and operating restrictions should be initiated, at least until the cause of the large value is either dismissed as ‘erroneous’ (sampling error for example) or fully understood and the unit has been deemed acceptable for continued operation.” See attached I&E Exhibit 3.

IV. ALLEGED VIOLATIONS

70. All allegations in paragraphs 1 through 69 are incorporated as if fully set forth herein.

71. One hundred and sixteen (116) days elapsed between the date Respondent was put on notice that the Failed Transformer was experiencing significant maintenance and operational issues, May 3, 2023, and the day the Failed Transformer ultimately failed on August 27, 2023.⁵

⁵ FirstEnergy’s failure to remedy the Failed Transformer was unknown to I&E and could not have reasonably been known by I&E until August 27, 2023, the date that it failed, at the earliest. Indeed, I&E first became aware of any potential violations related to FirstEnergy’s provision of service in Bradford, PA upon receipt of Representative Causer’s letter dated January 9, 2024.

72. The National Electric Safety Code (“NESC”) Section 012(A) directs that all electric supply lines and equipment shall be designed, constructed, operated, and maintained to meet the requirements of the NESC.

73. NESC Section 121(A) directs that electric equipment shall be inspected and maintained at such intervals as experience has shown to be necessary and any equipment found to be defective shall be put in good order or permanently disconnected.

COUNT ONE

74. All allegations in paragraphs 1 through 73 are incorporated as if fully set forth herein. Respondent failed to maintain the integrity of its distribution system in conformity with NESC Sections 012(A) and 121(A), in that Respondent did not maintain its Failed Transformer as necessary and when it was found to be defective Respondent did not put it in good working order or permanently disconnect it. If proven, this is a violation of 66 Pa.C.S. § 2807(a) (Duties of electric distribution companies). This violation continued for one hundred sixteen (116) days.

COUNT TWO

75. All allegations in paragraphs 1 through 73 are incorporated as if fully set forth herein. Respondent failed to comply with the minimum safety standards established by the National Electric Safety Code, specifically NESC Sections 012(A) and 121(A), in that Respondent did not maintain its Failed Transformer as necessary and when it was found to be defective Respondent did not put it in good working order or permanently disconnect it. If proven, this is a violation of 52 Pa. Code § 57.28(b) (Electric Safety Standards). This violation continued for one hundred sixteen (116) days.

COUNT THREE

76. All allegations in paragraphs 1 through 73 are incorporated as if fully set forth herein. Respondent failed to furnish and maintain adequate, efficient, safe and reasonable service and facilities and make such repairs, changes, alterations, substitutions, extensions and improvements in or to its service and facilities necessary or proper for the accommodation and safety of its customers, employees and the public, thereby placing the safety of its customers, employees and the public in danger, in that Respondent failed to maintain the Failed Transformer in accordance with NESC Sections 012(A) and 121(A), by failing to maintain its Failed Transformer as necessary and when it was found to be defective Respondent did not put it in good working order or permanently disconnect it. If proven, this is a violation of 66 Pa.C.S. § 1501 (Character of Service and Facilities). This violation continued for one hundred sixteen (116) days.

COUNT FOUR

77. All allegations in paragraphs 1 through 73 are incorporated as if fully set forth herein. Respondent failed to use reasonable effort to properly warn and protect the public from danger, or exercise reasonable care to reduce the hazards to which employees, customers, the public and others may be subjected to by reason of its provision of electric utility service and its associated equipment and facilities, in that Respondent was on notice, via the May 2023 Report, that the Failed Transformer was experiencing major mechanical and operational issues and ran the Failed Transformer to the point of failure on August 27, 2023, without engaging in efforts to inspect, investigate, or remediate the issues. If proven, this is a violation 52 Pa. Code § 57.28(a) (Electric Safety Standards). This violation continued for one hundred sixteen (116) days.

COUNT FIVE

78. All allegations in paragraphs 1 through 73 are incorporated as if fully set forth herein. Respondent failed to furnish and maintain adequate, efficient, safe and reasonable service and facilities, or make repairs, changes, alterations, substitutions, extensions and improvements in or to the service and facilities necessary or proper for the accommodation, convenience and safety of its patrons, employees and the public and failed to ensure that service was reasonably continuous and without unreasonable interruptions or delay, in that Respondent was on notice, via the May 3, 2023 Delta-X Report, that the Failed Transformer was experiencing major mechanical and operational issues and ran the Failed Transformer to the point of failure on August 27, 2023, without engaging in efforts to inspect, investigate, or remediate the issues. If proven, this is a violation of 52 Pa. Code § 57.194(a) (Distribution system reliability). This violation continued for one hundred sixteen (116) days.

COUNT SIX

79. All allegations in paragraphs 1 through 73 are incorporated as if fully set forth herein. Respondent failed to repair or replace a critical maintenance problem that affected the integrity of the circuit within 30 days of discovery, in that Respondent was on notice, via the May 2023 Report, that the Failed Transformer was experiencing major mechanical and operational issues and ran the Failed Transformer to the point of failure on August 27, 2023, without engaging in efforts to inspect, investigate, or remediate the issues. If proven, this is a violation 52 Pa. Code § 57.198(n)(5) (Inspection and maintenance standards). This violation continued for eighty-six (86) days.

COUNT SEVEN

80. All allegations in paragraphs 1 through 73 are incorporated as if fully set forth herein. Respondent failed to furnish and maintain adequate, efficient, safe and reasonable service and facilities and make such repairs, changes, alterations, substitutions, extensions and improvements in or to its service and facilities necessary or proper for the accommodation and safety of its customers, employees and the public, thereby placing the safety of its customers, employees and the public in danger, in that Respondent was on notice, via the May 3, 2023 Delta-X Report, that the Failed Transformer was experiencing major mechanical and operational issues and ran the Failed Transformer to the point of failure on August 27, 2023, without engaging in efforts to inspect, investigate, or remediate the issues. If proven, this is a violation 66 Pa.C.S. § 1501 (Character of Service and Facilities). This violation continued for one hundred sixteen (116) days.

COUNTS EIGHT THROUGH FOURTEEN

81. All allegations in paragraphs 1 through 73 are incorporated as if fully set forth herein. Respondent failed to adhere to its tariff, specifically Section 21 of its Electric Service Tariff, in that Respondent improperly denied the damage claims of no less than seven customers on the basis of “non-preventable, sudden, and unforeseen transformer failure” in spite of the fact that Respondent was on notice, via the May 3, 2023 Delta-X Report, that the Failed Transformer was experiencing major mechanical and operational issues and ran the Failed Transformer to the point of failure on August 27, 2023, without engaging in efforts to inspect, investigate, or remediate the issues. Each improper denial of a customer damage claim represents a separate violation. If proven, this is a violation 66 Pa.C.S. § 1303 (Adherence to tariffs).

COUNT FIFTEEN

82. All allegations in paragraphs 1 through 73 are incorporated as if fully set forth herein. Respondent failed to furnish and maintain adequate, efficient, safe and reasonable service and facilities and make such repairs, changes, alterations, substitutions, extensions and improvements in or to its service and facilities necessary or proper for the accommodation and safety of its customers, employees and the public, thereby placing the safety of its customers, employees and the public in danger, in that Respondent did not know and understand its electric distribution system, in particular, Respondent believed that the Failed Transformer had a top rating of 7,840 kVA, in contradiction to its Distribution System Planning Criteria that limits rectangular core transformers to their nameplate rating, which was 5,600 kVA for the Failed Transformer. If proven, this is a violation 66 Pa.C.S. § 1501 (Character of Service and Facilities).

V. REQUEST FOR RELIEF

83. Due to Respondent's failure to follow the National Electric Safety Code, failure to inspect, investigate, and remediate the Failed Transformer, failure to adhere to its tariff, and failure to understand its system, I&E proposes that Respondent pay a total civil penalty of Two Hundred Twenty-Five Thousand Dollars (\$225,000). The civil penalty shall not be tax deductible pursuant to Section 162(f) of the Internal Revenue Code, 26 U.S.C.S. § 162(f) or passed through as an additional charge to FirstEnergy customers in Pennsylvania.

84. In addition to the civil penalty, I&E proposes the following corrective actions, pursuant to Section 57.197(a)(1) of the Commission's regulations, 52 Pa. Code § 57.197(a)(1):

- a. Respondent shall pay all customer damage claims related to the August 27, 2023 transformer failure and the resulting September 5, 2023 overloading of the recloser at the Mill Street Substation, in accordance with its tariff.
- b. Provide Electric Safety Division with a report identifying all transformers in FE Pennsylvania systems with failing oil tests, all transformer failures, and all transformer replacements during the preceding three years.
- c. Provide Electric Safety Division with an annual report identifying all transformers in FE Pennsylvania systems with failing oil tests, all transformer failures, and all transformer replacements over the next three years.
- d. Provide the Electric Safety Division with all customer complaints and damage claims that correlate in timing and could be caused by the failing / failed transformers in paragraphs b & c.
- e. Review equipment in Bradford and the surrounding areas for system integrity.
- f. Review switching step procedures in Bradford and the surrounding area to assure procedures are up to date and that the equipment referenced in the procedures can perform the tasks required.
- g. Provide the Electric Safety Division with the priority of replacement policies for replacement of power transformers in substation facilities based on oil sampling test results.
- h. Provide the Electric Safety Division with the priority of replacement scheduling policies for the replacement of failing power transformers in substation facilities.
- i. Provide training to field and operation personnel to recognize any signs of early transformer failure, proper transformer maintenance, and operation.
- j. Issue a company-wide Advisory Bulletin highlighting the issues identified in this Formal Complaint to prevent recurrence of such events.

WHEREFORE, the Pennsylvania Public Utility Commission's Bureau of Investigation and Enforcement hereby requests that the Commission: (1) find Respondent to be in violation of the Public Utility Code, Commission regulations, and/or Code of Federal Regulations for each of counts set forth herein; (2) impose a cumulative civil penalty upon Respondent in the amount of Two Hundred Twenty-Five Thousand Dollars (\$225,000); (3) direct Respondent to perform each of the corrective actions detailed in this Complaint; and (4) order such other remedies as the Commission may deem to be appropriate.

Respectfully submitted,



Colby Widdowson
Prosecutor
PA Attorney ID No. 326185

Stephanie M. Wimer
Deputy Chief Prosecutor
PA Attorney ID No. 207522

Pennsylvania Public Utility Commission
Bureau of Investigation and Enforcement
Commonwealth Keystone Building
400 North Street
Harrisburg, PA 17120

Dated: May 13, 2026


**BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION**

Pennsylvania Public Utility Commission,	:	
Bureau of Investigation and Enforcement,	:	
Complainant	:	
	:	
v.	:	Docket No. C-2026-
	:	
FirstEnergy Pennsylvania Electric Company,	:	
Respondent	:	

VERIFICATION

I, Don Trumpie, Electric Safety Engineer, hereby state that the facts above set forth are true and correct to the best of my knowledge, information, and belief and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa.C.S. § 4904 relating to unsworn falsification to authorities.

Date: May 13, 2026



Don Trumpie
Engineer
Electric Safety Division
Pennsylvania Public Utility Commission
Bureau of Investigation and Enforcement

I&E Exhibit 1
CONFIDENTIAL

I&E Exhibit 2
CONFIDENTIAL

I&E Exhibit 3

IEEE Guide for the Interpretation of Gases Generated in Mineral Oil-Immersed Transformers

IEEE Power and Energy Society

Developed by the
Transformers Committee

IEEE Std C57.104™-2019
(Revision of IEEE Std C57.104-2008)

IEEE Guide for the Interpretation of Gases Generated in Mineral Oil-Immersed Transformers

Developed by the

Transformers Committee
of the
IEEE Power and Energy Society

Approved 13 June 2019

IEEE SA Standards Board

Abstract: Detailed procedures for interpreting Dissolved Gas Analysis results are described in this guide. The document details: 1) Overview of gas generation in transformer and DGA process; 2) The purpose and application of DGA; 3) DGA quality verification and DGA limitations; 4) DGA interpretation and norms; 5) Fault type definitions and identification; 6) Case studies and interpretation example. The intent is to provide the operator with useful information concerning the serviceability of the equipment. An extensive bibliography on gas evolution, detection, and interpretation is included.

Keywords: DGA, gas analysis, IEEE C57.104™, mineral oil, mineral oil-immersed transformers, transformers

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Introduction

This introduction is not part of IEEE Std C57.104-2019, IEEE Guide for the Interpretation of Gases Generated in Mineral Oil-Immersed Transformers.

IEEE Std C57.104™-1991 was officially withdrawn by IEEE based on recommendation by the Transformers Committee of the IEEE Power and Energy Society at the end of 2005. IEEE Std C57.104-2008 was issued with minor changes to address some of the most pressing issues identified from the 1991 version (such as correcting typos, factual errors, and the values listed in Table 1 of the 1991 version of the guide) for use by the industry.

Upon publication of the 2008 document, the working group immediately began the process of further revision to the guide to reflect additional advances in current knowledge and trends, and to incorporate relevant and new material presented during several meetings of both the IEEE Std C57.104 Working Group Task Force (WG TF) leaders and general IEEE Transformer Committee meetings. In addition, results from the analysis of more than a million pieces of laboratory DGA data has resulted in revision of several tables in this guide.

Changes in this revised guide are as follows:

- All clauses reviewed and updated.
- Reduction of Table 1 from four conditions to three DGA status based on 90th and 95th percentile values.
- Modification of Table 1 to include several subcategories and split between Table 1 (90th percentile) and Table 2 (95th percentile) based on results of a large statistical study (Annex A).
- Removal of TCG and TDCG interpretation and associated Table 2 and Table 3.
- Introduction of delta and rate tables: Table 3 and Table 4.
- New interpretation flowchart and methodology with illustrative examples (Annex B).
- Updated fault definitions in Annex C.
- Introduction of the Duval Triangle and pentagon interpretations methods in 6.2 and in Annex D and removal of the Doernenberg and key gas methodology from main text.
- Addition of case studies in Annex E.
- Addition of Normalized Energy Intensity (NEI) methodology in Annex F.
- Preservation of deleted material with historical values in Annex G.
- An updated bibliography in Annex H.

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IEEE Guide for the Interpretation of Gases Generated in Mineral Oil-Immersed Transformers

1. Overview

Over the years, since transformer dissolved-gas analysis (DGA) was first used in the 1960s, accumulated experience and new technology have led to significant improvements. Gas formation processes and severity assessment are now better understood. Chart-based methods and slide rules have been replaced by modern computer-based technologies that bring improved communications, data management, graphical and computational aids, analysis, and electronic reports. Instrument technology has advanced greatly, providing better laboratory instruments, as well as field-portable gas analyzers and on-line gas monitors.

The fundamental purpose of DGA is to discriminate between normal and abnormal conditions. More specifically, DGA aims to provide a reliable and economical method of detecting faults, which may present unacceptable possibility of damage or near-term failure. In transformers, a fault is revealed by the production of new gases. In many cases, active faults generate gases at such a high rate that detection and assessment do not require finesse. On the other hand, the gases generated by a subtle, incipient, or intermittent fault can sometimes be difficult to distinguish from the background of residual gases already present in the transformer during “normal” operation. This situation can arise because of normal variations in gas concentrations due to load and environmental conditions; unavoidable random “noise” from measurement uncertainty (method repeatability and reproducibility), as well as data quality issues arising from poor sampling technique, exposure of samples to air, or mislabeling of samples. As with any decision process based on data subject to “random” interference, a method must be developed to minimize the number of false positives while also minimizing the number of false negatives, i.e., failures to detect real abnormalities.

DGA is one of the most widely used diagnostic tools for transformer condition assessment because experience has proven it to be an effective tool.

Even so, DGA has limitations that warrant some precautions in interpretation, such as:

- Samples can be incorrectly collected, identified, or processed. The veracity of dissolved gas data should be checked before remedial or emergency action is undertaken (i.e., a confirmation sample).
- Unusual causes of gas formation can misdirect DGA diagnosis. For example, when a pattern consistent with “stray gassing” is observed, the possibility of that explanation should be carefully considered before further action is taken.

- Gas concentrations alone are not a sufficient indicator of transformer condition. An understanding of how the gases were produced, and at what rates, is usually needed for judging the significance of the gases found in a sample.
- Multiple phenomena occurring simultaneously, or at different times, can confuse analysis. Examination of changes in gas concentrations helps to reveal the active processes.
- Rates and accelerations of gas formation provide the best basis for evaluating process development, but proper determination of gas formation rates and accelerations requires several measurements over time.
- Characterizing the rate and pattern of gas formation is not always sufficient to identify the origin of gas generation. Comparison with historical information, industry trends, and documented case histories can be helpful. Additional diagnostic tools, such as on-line and off-line electrical, mechanical or acoustic testing, internal inspection and other insulating liquid testing, may be needed.

This guide is based on the collective experience of the industry in using the strengths of DGA and managing its limitations to detect abnormal gas formation, identify its most probable causes, and follow its development to assess the severity of a developing abnormality.

1.1 Scope

This guide applies to mineral oil-immersed transformers and addresses:

- a) The theory of combustible gas generation in a transformer
- b) The interpretation of gas analysis
- c) Suggested operating procedures
- d) Various diagnostic techniques, such as Key Gases, Rogers Ratios, Duval Triangle, and other methods
- e) Case studies and examples
- f) Evaluation criteria and guidelines
- g) A bibliography of related literature

1.2 Purpose

The purpose of this document is to provide a guide for evaluating dissolved gases analysis results from mineral oil-immersed transformers using statistical based analytical tools and fault interpretation methods.

1.3 Limitations to use of this document

This guide is applicable to mineral oil-immersed transformers and reactors of all types, sizes, voltage classes, construction, and usages, except those excluded in 1.3.

This guide is not applicable to DGA samples taken during factory testing. For DGA samples taken during factory temperature rise tests, refer to IEEE Std C57.130™ [B105].¹

¹ The numbers in brackets correspond to those of the bibliography in Annex H.

This guide is not applicable to load tap changers (LTC) and to transformers with main tank insulating liquid in contact with LTC insulating liquid, for example, a common expansion tank (refers mostly to in-tank type LTCs) or common air space inside the expansion tank. Load Tap Changer DGA, is covered by IEEE Std C57.139™ [B106].

This guide is not applicable to transformers using any insulating liquid other than mineral oil. Transformers using an ester-based liquid, are covered by IEEE Std C57.155™ [B109]. Transformers using silicone liquid, are covered by IEEE Std C57.146™ [B107].

The user of this guide must consider the internal components of the transformer when choosing to apply the guide to specific transformer types such as wind turbine transformers or network transformers. Such transformers may have auxiliary components such as load break switches (as an example) immersed in the same oil as the transformer itself. As such a component produces an electrical arc and combustible gases as a normal part of its operation, the user of this guide must consider the possibilities that:

- The transformer oil DGA results may be almost entirely a result of switch operation, and not an accurate reflection of the health of the transformer itself.
- The gases produced by the switch operation may be much greater than the gases produced by the transformer itself, and therefore may mask any problems associated with the transformer that might otherwise be detectable via DGA interpretation.

Note that the initial analysis of the data received in preparation of this guide clearly indicated that DGA results from transformers identified as wind turbine or network transformers often had excessively elevated typical values, in some case two orders of magnitude higher than the rest of the DGA database. There was no information to indicate if the transformers were healthy or under extreme distress. Therefore, the DGA data subset from wind turbine and network transformers was not included in the study to obtain the norms used in this guide. Consequently, if the user of this guide applies the norms presented herein to such transformer types, the result may often be high DGA status levels.

In the case of wind turbine transformers in particular, they have special operating conditions in that they are closely connected to power electronics and have frequently and widely fluctuating loads. Some of the earlier generation designs of these transformers were not adequately robust for such operating conditions, and hence the often elevated gas values are seen. For further insight into wind turbine transformer design and their particular DGA issues, refer to “Wind Power Transformer Design” [B102] and “Unusual DGA results in wind turbine transformers” [B129].

Sampling of transformer insulating liquid for DGA should be done by suitably trained personnel following standard procedures such as ASTM D923.² The measurement of gas concentrations should be performed by an analytical laboratory according to the methods defined in ASTM D3612, or by suitably trained personnel using a portable instrument, or by a suitably connected on-line monitoring device.

The interpretation of DGA data should be performed by a suitably trained and experienced person. Computer analysis of the DGA results with tools such as spreadsheets, databases, analytical software, or maintenance management systems, can be used when evaluating the health and condition of a transformer. Any other relevant information, such as transformer nameplate, factory test reports, operational and maintenance records, in service test results and environmental conditions, should also be considered in such evaluation. An aggregate of all available information is generally considered the optimal approach when a detailed interpretation is required. The nature of the interpretation also depends upon the context or application of the DGA.

For various reasons, some of which are explained in this guide, DGA results can sometimes be indeterminate or misleading, and sometimes DGA can fail to detect or identify a fault that may be present.

² Information on references can be found in Clause 2.

Drastic or costly measures should not be taken based on DGA results alone, particularly not on an individual, isolated DGA sample, without confirmation by additional DGA results and/or other tests such as electrical performance tests, expert consultation, and due regard to local operating conditions, requirements, and safety issues. It should also be noted that DGA is a detection and diagnostic tool, not a predictive technique. It can only detect an existing or past condition and has no capability to “predict” any future condition. However, when a condition exists, DGA can be used to track and evaluate its evolution over time.

1.4 Word usage

The word *shall* indicates mandatory requirements strictly to be followed in order to conform to the standard and from which no deviation is permitted (shall equals is required to).^{3,4}

The word *should* indicates that among several possibilities one is recommended as particularly suitable, without mentioning or excluding others; or that a certain course of action is preferred but not necessarily required (should equals is recommended that).

The word *may* is used to indicate a course of action permissible within the limits of the standard (may equals is permitted to).

The word *can* is used for statements of possibility and capability, whether material, physical, or causal (can equals is able to).

2. Normative references

The following referenced documents are indispensable for the application of this document (i.e., they must be understood and used, so each referenced document is cited in text and its relationship to this document is explained). For dated references, only the edition cited applies. For undated references, the latest edition of the referenced document (including any amendments or corrigenda) applies.

ASTM D923, Standard Practices for Sampling Electrical Insulating Liquids.⁵

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

IEC 60567, Oil-filled electrical equipment—Sampling of gases and of oil for analysis of free and dissolved gases—Guidance.⁶

IEEE Std C57.93TM, IEEE Guide for Installation and Maintenance of Liquid-Immersed Power Transformers.^{7,8}

IEEE Std C57.143TM, IEEE Guide for Application for Monitoring Equipment to Liquid-Immersed Transformers and Components.

³ The use of the word *must* is deprecated and cannot be used when stating mandatory requirements, *must* is used only to describe unavoidable situations.

⁴ The use of *will* is deprecated and cannot be used when stating mandatory requirements, *will* is only used in statements of fact.

⁵ ASTM publications are available from the American Society for Testing and Materials (<http://www.astm.org/>).

⁶ IEC publications are available from the International Electrotechnical Commission (<http://www.iec.ch>) and the American National Standards Institute (<http://www.ansi.org/>).

⁷ IEEE publications are available from The Institute of Electrical and Electronics Engineers at <http://standards.ieee.org/>.

⁸ The IEEE standards or products referred to in this clause are trademarks of The Institute of Electrical and Electronics Engineers, Inc.

IEEE Std C57.152™, IEEE Guide for Diagnostic Field Testing of Fluid-Filled Power Transformers, Regulators, and Reactors.

3. Definitions, acronyms, and abbreviations

3.1 Definitions

For the purposes of this document, the following terms and definitions apply. The *IEEE Standards Dictionary Online* should be consulted for terms not defined in this clause.⁹

continuous monitoring: A test protocol in which a transformer is tested at very short time intervals (e.g., daily or several times per day) for characterization of abnormal gas formation, and very early warning of severely abnormal gas formation. This protocol could utilize suitably connected on-line monitoring devices.

DGA status: Classification of DGA results based on statistical norms.

DGA test protocols: A program of DGA applied to a transformer or to a transformer population.

dissolved-gas analysis (DGA): The identification, measurement, and interpretation of gases dissolved in the insulating liquid of electrical equipment.

dissolved-gas analysis norms: Reference values for gas concentrations, rates of change, and ratios that are used to define various degrees of abnormality or unacceptability.

electrical discharge fault: Arcing or sparking between conductive components at different potential.

NOTE—See Annex C.1.

failure: A transformer is considered to have failed when, due to defect, damage, or deterioration, it becomes incapable of remaining in its intended service and either ceases to function (for example by catastrophic failure) or has to be taken out of service for repair or replacement.

fault: A fault is an unplanned occurrence or defect in a transformer that allows an abnormal internal diversion of energy, which could cause damage and lead to failure or increased risk of failure.

gas concentrations: The concentration of a gas dissolved in insulating liquid is expressed in microliters per liter ($\mu\text{L/L}$), also referred to as parts per million by volume (ppm v/v), both expressed at standard temperature and pressure (STP) conditions (0 °C and 101.325 kPa).

initial verification: A set of DGA performed when a new or repaired transformer is entered into service, or when a DGA screening test protocol is resumed for a transformer after several years without sampling (e.g., after a storage period).

partial discharge fault: An electric discharge that only partially bridges the insulation between conductors, and that could occur adjacent to a conductor.

NOTE—See Annex C.1.

⁹*IEEE Standards Dictionary Online* is available at: <http://dictionary.ieee.org>.

rate: Constant gas generation over a certain period, expressed in $\mu\text{L}/\text{L}/\text{year}$. In the context of this guide, rate is computed by linear best fit from 3 to 6 consecutive DGA covering a period of at least 4 months to a maximum of 24 months.

screening: A test protocol in which all transformers in a population are tested at regular time intervals (e.g., every year) to identify units which may require additional attention or remedial action. This protocol is used to identify transformers with potential fault activity.

surveillance: A test protocol in which a transformer is tested at relatively short time intervals (e.g., months, weeks, or days) for the purpose of detecting and characterizing any gas formation that may occur and provide early warning of a rapidly worsening condition. This protocol is used to confirm fault activity and determine fault severity. It could also be used when unit condition changes, such as after a relocation of the unit or a loading increase.

thermal fault: An excessive temperature rise, in the insulation or any internal component.

NOTE—See Annex C.1.

3.2 Acronyms and abbreviations

C	possible carbonization of paper
D1	discharges of low energy
D2	discharges of high energy
DGA	dissolved gas analysis
GIOS	gas in oil standard
GSU	generator step-up transformer
LTC	load tap change (previously designed OLTC)
$\mu\text{L}/\text{L}$	microliter per liter; equivalent to ppm v/v (parts per million, volume/volume)
ND	not determined or not detected
NEI	normalized energy intensity
O	overheating of paper or mineral oil
OLTC	on load tap changer (deprecated, replaced by LTC)
PD	partial discharges
QA	quality assurance program
R	catalytic reactions
S	stray gassing

STP	standard temperature and pressure (0 °C and 1 atm)
T1, T2, T3	thermal faults

4. The nature, purpose, and application of dissolved-gas analysis

Transformer mineral oils are mixtures of many different hydrocarbon molecules, and the decomposition processes for these hydrocarbons in thermal or electrical faults are complex. The fundamental steps of gas generation are the breaking of carbon-hydrogen and carbon-carbon bonds. Active hydrogen atoms and hydrocarbon fragments are formed. These free radicals can combine with each other to form gases, molecular hydrogen, methane, ethane, etc., or can recombine to form new, condensable molecules. Further decomposition and rearrangement processes lead to the formation of products such as ethylene and acetylene and, in the extreme, to modestly hydrogenated carbon in particulate form. These processes are dependent on the presence of individual hydrocarbons, on the distribution of energy and temperature in the neighborhood of the fault, and on the time during which the mineral oil is thermally or electrically stressed.

The quantity of hydrogen formed can be relatively high and can be insensitive to temperature for some fault types, such as some stray gassing, partial discharges (PD) and catalytic faults. Formation of acetylene becomes appreciable only at temperatures nearing 1000 °C. Formations of methane, ethane, and ethylene also each have unique dependences on temperature. See Figure 1.

The thermal decomposition of mineral oil-impregnated cellulose insulation produces carbon oxides and some hydrogen or methane from the mineral oil. The rate at which they are produced depends exponentially on the temperature and directly on the volume of material at that temperature.

4.1 The nature of dissolved-gas analysis

Dissolved gas analysis (DGA) is the identification, measurement, and interpretation of the gases dissolved in the insulating liquid. The principal gases used in identification of faults (so-called “fault gases”) are hydrogen (H₂); methane (CH₄); ethane (C₂H₆); ethylene (C₂H₄); acetylene (C₂H₂); carbon monoxide (CO); and carbon dioxide (CO₂). Oxygen (O₂) and nitrogen (N₂) are also measured and used in the interpretation, although they are not fault by-products.

The gases containing both of the elements carbon (C) and hydrogen (H₂) are called hydrocarbons, and the gases CO and CO₂ are called carbon oxides. Hydrogen, the hydrocarbon gases, and carbon monoxide are combustible gases, while oxygen, nitrogen, and carbon dioxide are non-combustible gases. Other gases that may be dissolved in the insulating liquid, such as argon (Ar) and higher molecular weight hydrocarbon gases, are ordinarily ignored for transformer DGA. Other light gases, such as propane and propylene, are also generated, but are not used in this guide.

The concentration of a gas dissolved in insulating liquid is expressed in microliters per liter (μL/L), also referred to as parts per million by volume (ppm v/v). The concentration of a gas in the gas mixture collected from a gas space is often expressed as percent by volume. All these quantities are corrected to standard temperature and pressure (0 °C and 101.325 kPa) for reporting in accordance with ASTM D3612. Rates of gas generation are commonly expressed in microliters per liter per day (μL/L/d), ppm per day (ppm/d), microliters per liter per year (μL/L/y), or ppm per year (ppm/y).

An appropriate sampling procedure, such as ASTM D923, should be followed to obtain a representative insulating liquid sample. To minimize gas loss and air contamination, a gas-tight glass syringe is the preferred sampling vessel. The sample is usually sent to an analytical laboratory, where a standard procedure, such as ASTM D3612, is followed for separating dissolved gas from the insulating liquid and using a gas chromatograph to measure the concentrations of individual dissolved gases. A field-portable

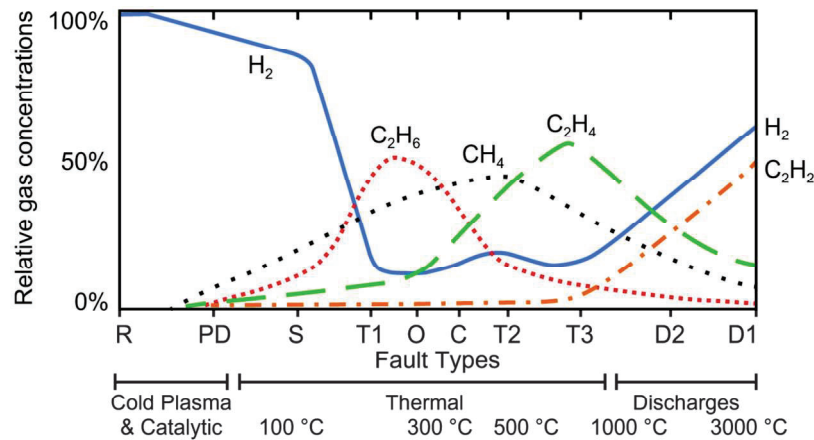
gas analyzer, which may or may not be a chromatograph, may be used for a quick determination of gas concentrations from a syringe sample. The use of gas monitors, connected directly to the transformer and automatically collecting and analyzing several samples per day, is increasingly common.

The result of a laboratory analysis is an electronic or paper report identifying the transformer, specifying the sample date, other sampling and processing information, and the concentrations of the gases listed above. Laboratory DGA reports often include interpretive or diagnostic remarks, as well as the data. Many laboratories also provide the analysis results in a data file upon request. Portable gas analyzers and gas monitors typically provide results in the form of an electronic report or a data file. Some portable gas analyzers omit one or more of the atmospheric gases (oxygen, nitrogen, carbon dioxide) from the analysis, and likewise some gas monitors measure only hydrogen or a few of the principal DGA gases.

It is necessary to subject DGA data to a quality check before interpretation. When results are accepted, their interpretation should take into account any earlier DGA results that may be available. The interpretation of transformer DGA results is the main subject of this guide.

The interpretation of gases dissolved in insulating liquid is based on the premise that a liquid immersed transformer in sound condition generates little or no fault gas under normal operating conditions. In preparation for service, the transformer is filled with unused mineral oil, which typically has also been vacuum processed during filling, so that it normally starts out with no dissolved combustible gas, a very small concentration of carbon dioxide, and low concentrations of dissolved oxygen and nitrogen. The transformer insulating liquid preservation system protects it from exposure to air (for a sealed transformer) and from moisture ingress. Under normal operation, the heat generated in the windings and core is absorbed by the insulating liquid and transported to the tank walls and cooling system, keeping the internal temperatures of the transformer within a range where thermal aging of the insulation system is acceptable (for a more information on thermal aging of insulation, see IEEE Std C57.91™ [B104]). Under normal circumstances, some gases, mainly carbon dioxide, carbon monoxide, and hydrogen, are generated very slowly by the aging of the cellulosic insulation and the insulating liquid. Significant concentrations of hydrogen and hydrocarbon gases can be generated within the mineral oil at normal service temperatures, rated loading or from material interaction (such as some metal passivators), even if no fault is present. This phenomenon is known as “stray gassing” (see C.2).

An internal defect, an abnormal system event or anomaly, or operation in environmental conditions outside the designed ranges can result in excessive energy dissipation in the transformer insulation system and may also cause harmful mechanical stress on windings and other internal structures. Some of the diverted energy acts on the insulating liquid or cellulose insulating material resulting in the generation of gases that dissolve in the insulating liquid and are also distributed to all available gas spaces in the transformer. The particular combination of gases that is generated in mineral oil depends on the nature of the fault process and is related to the energy level and temperature at the fault location, as schematically illustrated in Figure 1 (see “Ongoing activities at IEEE, IEC and CIGRE on DGA” [B87]).



NOTE—See 3.2 for faults acronym and Annex C for faults type definition

Figure 1—Relative percentage of dissolved gas concentrations in mineral oil as a function of temperature and fault type

4.2 The purpose of DGA

The underlying purpose of DGA, in addition to the more obvious purpose of attempting to detect and identify a possible fault, is to improve safety and equipment reliability while reducing cost. Safety and reliability are improved through awareness of transformer condition, early detection of faults, and monitoring of suspect transformers. Cost reduction is achieved by avoidance or mitigation of transformer damage and failures, and also by optimization of operation and maintenance.

4.3 The application of DGA

It is helpful to distinguish ways in which DGA is used:

- Basic risk management
- Detection and monitoring of abnormalities
- Quality assurance metric
- Fault type identification
- In-service tripping investigation

Methods of fault type identification are described in 6.2 and Annex D. Case studies of DGA application are presented in Annex E.

4.3.1 Basic risk management

DGA before placing a transformer into service provides an initial baseline, and periodic DGA screening throughout a transformer's lifetime is performed to evaluate its operating condition and to prioritize attention to any transformer that may be generating combustible gases. The frequency of routine DGA screening may be based on considerations such as the economic cost of a forced outage, service criticality, contractual requirements (e.g., an insurance policy), and safety.

Other considerations are the warranty status, replacement cost, and relative importance of the transformer. Annual DGA screening is common.

If the expected economic cost of forced outage or of replacement is very high, online monitoring or frequent (monthly or quarterly) periodic DGA may be justified. IEEE Std C57.143 contains useful guidance regarding the use of gas monitors in transformer asset management.

Abnormal DGA results can provide early warning of a developing problem, can identify the nature of the process that is generating the fault gases, and (via rates of change or increment magnitudes) can indicate how energetic the process is. Experience has shown that not all abnormal gassing events are necessarily related to transformer deterioration or permanent damage. A complete transformer condition assessment should also include other considerations as much as possible, such as electrical test results, recent or historical systems events, and physical inspection. As explained in 1.3 and 6.1, high gas levels do not necessarily predict a future failure.

Users should have in place a transformer DGA protocol or program taking into consideration the DGA status as described in 5.3. This protocol could vary due to several parameters such as transformer type, size, age, criticality, personnel availability, maintenance practice, and other economic considerations.

The general practice, when there is no indication of an abnormality in the operation of the transformer, is to sample the transformer insulating liquid for DGA on a time basis, with the period between samples typically ranging from a few months (for the larger or most critical units), to 1 or 2 years. In some cases, the use of an on-line gas monitor could be part of this protocol.

It should be noted that longer periods between DGA samples can increase the possibility of a fault going unobserved while the transformer deterioration progresses toward failure.

4.3.2 Detection and monitoring of abnormalities

If DGA samples are taken and the results are studied with sufficient frequency, then some major faults are easy to detect because of significant production of fault gas. It is possible, although challenging, to distinguish the lesser gas production of incipient or intermittent faults from the normal temperature-driven variation of residual gas, especially under the influence of measurement uncertainty, occasional sampling problems, or gas loss. However, some ancillary device problems, mechanical, or externally caused failures are not preceded by any DGA forewarning.

When abnormal gas generation is confirmed, the DGA results could be used to identify the apparent fault type (see 6.2 and Annex D). Beyond fault identification, gas increments or rates of gas formation indicate the relative severity of the fault. Changes in increments, rates, or evolution of the fault type (e.g., from a lower energy fault type to a higher energy fault type) may indicate worsening or moderation of the fault process. Unless the gassing behavior is so extreme as to motivate immediate shutdown, it may be prudent to take DGA samples more frequently and monitor long enough to determine the gas formation rates, to investigate whether the abnormality is transient, intermittent, or on-going, and to determine whether the fault type and severity seems to be evolving. If, for operational reasons, it is necessary to continue operating a gassing transformer, more frequent DGA surveillance may provide early warning of increased gas generation, which may indicate that the transformer's condition is worsening.

4.3.3 Quality assurance metric

Another application of DGA is verification of previous DGA measurements and measurement quality assurance. DGA is sometimes performed to provide confirmation of earlier DGA results or gas monitor readings.

Duplicate samples can be used to check laboratory consistency, while gas-in-oil standard solutions (gas-in-oil samples of known, precise gas quantities usually purchased from a certified gas sample supplier) can be used to check both consistency and accuracy. Specific guidelines are provided in 5.1 and 5.2.

4.3.4 DGA samples following a transformer trip

Laboratory DGA samples can be taken as an initial response to a transformer relay alarm or trip (see IEEE Std C57.152-2013, Table 1 [B108]). Relay trips may result in no external indications of transformer damage, therefore, electrical testing and DGA is used to evaluate the condition for continued operation (see “Guide for Transformer Fire Safety Practices” [B73] and “Transformer reliability survey” [B74]). The amount of time after a transformer trip should be noted when obtaining a DGA sample. The location of a fault inside of the transformer and the insulating liquid flow rate have a direct relation to the amount of time for the combustible gases to be distributed throughout the transformer insulating liquid and reach the sampling port of the transformer tank. As examples, a forced flow cooling system may have a short gas transport time if the circulating pumps remain in operation following the trip, while natural convection flow on a very cold day or with a low load prior to the trip can take more than 24 h to completely distribute dissolved gases. Therefore, additional DGA samples may need to be scheduled to monitor for a stable dissolved gas-in-oil condition.

The device or relay that alarmed or caused the transformer to trip will likely suggest the additional testing protocols to be followed. For example, protocol for the trip of a distant breaker may include taking a DGA sample from the downstream transformer even though the breaker is immediately reclosed, and the transformer was brought back into service. But protocol for a differential current trip, normally associated with an internal transformer fault, may suggest that electrical testing of the transformer is required as a condition for continued service, in addition to DGA testing.

The decision to return a transformer to service will depend on the electrical test results, physical inspection results, and is influenced by system needs. Post-trip DGA results should be compared to the previous transformer DGA history and reviewed for changes in the types of gases reported and their concentrations, which may indicate a change in the equipment condition. Suspected changes to the equipment condition should be verified with a confirmation DGA sample. This is also crucial as a baseline for comparing future DGA results.

4.4 DGA sampling context

The interpretation of DGA data should be performed with due regard to the purpose of the sampling. The following basic sampling contexts are the most common ones encountered:

- a) **Initial sample**—An initial DGA sample is one that is interpreted without regard to previous samples. For example, a sample taken before or shortly after energizing a new transformer as part of initial test protocol (see 5.3.1), after major repairs or modifications, or on a transformer that has no previous DGA data associated with it would be considered an initial sample. The gas concentrations and other measurement data associated with an initial sample can be used as baseline values for comparison with later data.
- b) **Periodic screening sample**—A periodic screening sample is one of a series collected at regular time intervals (for example, six months or one year) for verifying that a transformer is operating normally. See 5.3.2.
- c) **Surveillance sample**—A surveillance sample is one of a series collected at shorter intervals (compared to periodic screening intervals) for characterizing a suspected fault or keeping close watch on a transformer’s condition during start-up, testing, high stress circumstances, or other exceptional operating conditions. See 5.3.3.
- d) **Continuous monitoring sample**—A continuous monitoring sample is one of a series of samples collected at a high rate (typically from more than one per day to one every few days) for maintaining a close watch on a transformer’s condition (see 5.3.4). An on-line dissolved gas monitor could also be used for that purpose. Continuous monitoring is typically applied in cases of higher economic risk; for example, protection of extremely critical or expensive transformers,

continuous condition assessment to help extend the service life of older transformers, or investigation and operational safety when a transformer is being operated with a fault or under extreme stress. The use of an on-line dissolved gas monitor with remote data collection capability is a safer alternative than manually extracting an on-site sample from a transformer that is severely gassing and may fail catastrophically without warning.

- e) **Incident investigation sample**—An incident investigation sample is a sample taken after an incident (e.g., gas relay tripping, close-in fault, etc.) to investigate whether the transformer has been damaged.
- f) **Quality assurance sample**—A quality assurance (QA) sample is one processed for the purpose of evaluating measurement accuracy, repeatability, or reproducibility. QA samples are not for transformer condition analysis. QA samples may be purchased or may be prepared as a gas-in-oil standard (see ASTM D3612). Where accuracy is not being evaluated and greater variation is tolerable, QA checking may be done using consecutive or split transformer samples.
- g) **Verification sample**—A verification or “check” sample is one that is drawn from a transformer and submitted for analysis and comparison with anomalous DGA results from a recent sample from the same transformer or recent gas monitor readings. See 5.2.

4.5 Procedures for obtaining samples from the transformer for laboratory analysis

All samples of insulating liquid taken from electrical apparatus for dissolved gas-in-oil analysis should be taken in accordance with ASTM D923. A gas-tight, glass syringe is the preferred container for DGA sample. The sampling procedure should always ensure that the samples are taken safely, without compromising the transformer insulating liquid level, without contaminating the sample with air, and without allowing air to enter the transformer during the sampling process.

Under certain fault conditions, some portions of the insulating liquid may have higher dissolved gas concentrations for several hours before complete mixing with the bulk of the insulating liquid has occurred. In these cases, where possible, samples should be obtained from more than one location on the transformer and a confirmation sample should be taken the following day.

Particular care should be taken that good sampling procedures are in place and are followed at all times. Proper personnel training for DGA sampling should be an integral part of the DGA policy. Particular attention should also be given on properly filling out the form accompanying samples, especially since DGA is applied to a large range of apparatus (main tank, bushings, cable, LTC, etc.) with different DGA interpretation methods (e.g., different types of insulating liquid).

All due safety precautions should be taken when sampling is performed. Particular attention in this respect should be given to avoid possible ingress of air into the transformer.

CAUTION

Sampling from a transformer tank when negative pressure is known or suspected should never be done, as it will result in air ingress and possible immediate or future catastrophic failure of the transformer.

Purging the sampling valve should be performed each time to avoid air ingress and to help guarantee a representative sample. To properly purge, the sampling system should be open to atmosphere when the transformer valve is initially opened to allow any trapped air to escape. The sample should be taken only when the valve has been purged of all trapped air and of stagnant insulating liquid. See “Where Does the Air Go? (Second Edition)” [B121].

Correct information about transformers, especially serial number and location, sampling compartment and location, reason for sampling, kV and MVA ratings, preservation type, type of insulating liquid,

transformer manufacturer and manufacturing year, cooling type, and nature of service (GSU, transmission, etc.) is helpful for DGA database management and proper interpretation of DGA data. Accurate identification and other relevant transformer information should also be supplied to the analytical laboratory.

5. DGA data interpretation

The interpretation of DGA data begins with the detection of an abnormal condition. When found, it should be followed by severity assessment and fault identification. The fault detection and severity assessment part of DGA consists of comparing the gas levels and rates of change, to their respective norms and assigning a status condition according to which norms (if any) were exceeded. When there is an indication of a problem, a fault identification or diagnosis should be obtained by a reliable technique, such as the Duval Triangle method. See 6.2 and Annex D. Graphical visualizations of the data in various ways as discussed in Annex E and Annex D often provides insights into fault identification, evolution, and severity. Other relevant information, such as maintenance activity records, electrical diagnostic test results, lightning strike occurrences, load history, etc., should be consulted to seek a better understanding of what may be causing the gassing activity, and to confirm or modify the DGA condition assessment. See Annex E for case studies of DGA interpretation.

The interpretation of DGA results can begin only after a data quality review to identify and correct data quality problems has been performed. It is important to understand that a review of data cannot identify all possible data quality problems. Therefore, when unexpected or alarming results are obtained, it is highly advisable to collect and process another sample to confirm results.

5.1 Data quality review

This subclause contains the recommended practices to be followed to ensure the quality of the DGA results data. The working group realizes that a data review at the level of detail provided in 5.1.1 to 5.1.8 is not practical for many users. Therefore, any data points that seem to be unusual, compared to the history of the prior samples, should be investigated.

A data quality review is necessary to identify signs of data corruption, which could confuse or mislead the interpretation of the data. Data corruption can occur throughout data management, work management, sampling, analysis, and reporting phases of producing DGA data. Each phase has its characteristic data issues.

Data management and work management systems sometimes contain and propagate incomplete and inaccurate equipment identification and information. Long after corrections are made, forms generated with incorrect information can be copied and used, sometimes for years. This type of error could also cause duplication of equipment in database or result in incorrect DGA interpretation (e.g., DGA from an LTC identified as from the main tank).

Sampling provides several opportunities for data corruption. For example, the sampler, using a blank field data form, can incorrectly transcribe nameplate information; using a preprinted field data form can reduce errors identifying the equipment. The sampler can introduce errors by waiting to label the samples after they have all been collected. The sampler can provide information on the field data form that is different from the information on the sample container, can collect the sample from the wrong sampling point, can use contaminated tubing and fittings, or can contaminate the sample with air. Laboratory testing also provides several opportunities for data corruption. Transcription errors, swapped samples, carryover contamination, air contamination, calibration errors, gas identification, and quantization errors are the most likely types.

Data quality review most often amounts to comparing current test information to prior test information. In the case of an initial sample, the reviewer is limited to reality checks. Confirming an error and identifying its source may require access to the sample records. In some cases, problems can be resolved by asking the laboratory to check their records. When data quality problems cannot be corrected, it is recommended to resample the equipment.

5.1.1 Transcription and typographical errors

Transcription and typing errors show up in characteristic ways. A sequence of values that are all shifted by one position, a skipped or missed value in a sequence of values, two values that are swapped, digits that are added or lost in a value and swapped digits in a value usually appear as abrupt changes in individual values or as strange individual values. For example, oxygen concentration shown as 508 when its previous values had been around four or five thousand; a digit was omitted. Another example: ethylene reported as 87 following several samples around 8, with no evidence of any other combustible gas change; this type of error could be caused by a dropped decimal point. Transcription or typing errors in an equipment identifier result in a misidentified unit.

5.1.2 Missing or duplicated data

Occasionally some values may be accidentally omitted or deleted from the data. Sometimes the data for an earlier sample may be reported again instead of the latest data. This is particularly likely when all gas concentrations, $\mu\text{L/L}$, are the same as the previous sample (normally some variation is to be expected, especially for the high values, such as CO_2 , N_2 and O_2).

5.1.3 Misidentified or swapped sample

An incorrect or incomplete serial number or other equipment identifier may associate a sample with equipment that it did not come from, or with equipment that simply does not exist. There can also be problems with identification of the sampling point (e.g., main tank instead of LTC) or incorrect notation of the sample date. A swap of samples causes the same misidentification.

5.1.4 Sample mishandling

5.1.4.1 Air exposure

A leaky syringe, poor sampling technique, or mishandling of the sample can expose the sample to air, resulting in loss of much of the hydrogen, often accompanied by an increase of oxygen and nitrogen. A very low hydrogen concentration (especially if hydrogen was higher in earlier samples), with an O_2/N_2 ratio above 0.2 (for sealed transformer), or O_2 and N_2 reported levels above saturation values, may indicate that the sample was exposed to air. Air exposure of a sample from a breather type transformer, where the insulating liquid is normally saturated with air, could be more difficult to detect.

5.1.4.2 Air contamination

Entrainment of air during sampling, handling or processing results in oxygen, nitrogen, oxygen/nitrogen ratio and total gas concentration changes. The amount of change ranges from barely perceptible to extreme. Without knowledge of the adulterating process, rates and changes of fault gases calculated from these should be considered suspect.

5.1.5 Cross contamination

The results of carryover contamination during sampling (e.g., reusing sampling tubes) or processing (e.g., storage in contaminated tank) can vary widely. Appearance of a trace gas or gases, appearance of a fault and change of fault identification are all characteristic of this problem. As with any question of quality, a significant change of condition should prompt confirmation with a follow-up test.

5.1.6 Inconsistent values

A single sample, which is drastically different from earlier samples from the same equipment, may belong to a different piece of equipment (e.g., from the LTC compartment instead of main tank), or it may indicate a fault. Confirmation by resampling may be necessary. If there are large inconsistencies in several successive samples, there could be a sampling or measurement problem.

5.1.7 Chronically absent or low hydrogen

If the hydrogen concentration is always extremely low, even when other combustible gases are not, and especially when hydrogen is also chronically low in other transformers, there may be a problem with sampling technique, leaky syringes, or measurement. It may be necessary to submit a quality control standard (with known gas concentrations) to confirm that the laboratory or portable gas analyzer is measuring hydrogen correctly.

5.1.8 Inconsistent O₂/N₂ ratio

Isolated large increases in the O₂/N₂ ratio, especially when correlated with decreases in hydrogen, may indicate an air exposure problem. Mistyped values for oxygen or nitrogen can cause the O₂/N₂ ratio to assume unusual or impossible values. The saturation value for air dissolved in mineral oil normally gives an O₂/N₂ ratio between 0.4 and 0.5. If the ratio begins to approach that value for sealed transformers, it would be prudent to look for air leaks. For transformers with a bladder equipped conservator, rapidly increasing concentrations of oxygen can indicate a leaky or ruptured bladder. For a transformer with an open breather, the O₂/N₂ ratio will change little (near 0.4 to 0.5), but the total reported amount of O₂ and N₂ levels could increase above saturation values in case of air ingress into the sample.

5.2 Reliability of DGA results

5.2.1 Accuracy

Highly inaccurate gas concentration measurements can lead to incorrect assessment of fault severity or misidentification of the fault type. In extreme cases, errors can lead to inappropriate and costly mitigative action such as premature removal from service. Failure to notice severe conditions when they do occur can result in unnecessary outages, damage, or failures.

Recommendations to have accuracies better than $\pm 15\%$ on DGA results to avoid misidentification of faults can be found in IEC 60567 and in "Report on Gas Monitors for Oil-Filled Electrical Equipment" [B71]. Several laboratories meet this requirement, but several others do not (with measurement errors as high as $\pm 60\%$ or more for some gases).

It should be noted however that, at the time of the preparation of this guide, no reproducibility or repeatability values are presently available in ASTM D3612 for method C (head space) to help DGA users

verify whether the DGA results they receive from their laboratories and on-line monitors are accurate enough or not. Such guidelines are presently available only from IEC and CIGRE. Laboratory quality control is a key aspect of choosing a laboratory but can be a very time-consuming activity. One example of quality check for laboratories is the ASTM Committee D27 Proficiency Testing Program.

The practical recommendation to DGA users in case of critical transformers with abnormally high gas levels or with high gassing rates, where DGA results provided by different laboratories and on-line monitors are widely different (especially if they indicate drastically different actions to be taken on the transformer), is to verify the general accuracy of the DGA results from a given source using gas-in-oil standards (GIOS) and following IEC 60567 and “Report on Gas Monitors for Oil-Filled Electrical Equipment [B71].

GIOS can be prepared by DGA laboratories, following Annex A1 of ASTM D3612 or section 6.3 of IEC 60567. They can also be purchased commercially. An example where the reproducibility of several DGA laboratories was evaluated with GIOS is given in Table 1 of ASTM D3612 for method A. The procedure for evaluating the accuracy of on-line monitors is indicated in Appendix B of “Report on Gas Monitors for Oil-Filled Electrical Equipment” [B71], which also uses GIOS.

At gas concentrations below about five times the DGA method detection limit (a few $\mu\text{L/L}$, depending on the method and the gas), relative measurement uncertainty can be large. It is not recommended to base fault type identification or practical decisions on such low values without some confirmation of their accuracy. It is not recommended to attempt fault identification using the methods described in 6.2 and Annex D if all of the gas levels are below the Table 1 values.

Particular caution in interpretation should be used when acetylene is the only gas above the Table 1 [1 to 2 $\mu\text{L/L}$ (ppm)] values but is still below five times the detection limits. Fault identification in such a case may be unreliable.

A DGA expert, a person with experience in both transformer operation and DGA results interpretation, might attempt fault identification, after applying additional rules, when all gases are below the Table 1 values, but are above five times the detection limits and the laboratory processes are proven to meet accuracy requirements. This could provide advance information on incipient faults. However, as noted above, the results may be highly unreliable due to the low levels of gases present and should be used with caution.

5.2.2 Consistency

When DGA results consistently fluctuate widely (30% or two to three times the values in Table 3) from one sample to the next, it usually indicates sampling or analytical errors. Therefore, the results should not be used for fault identification or severity assessment, unless the reasons for these fluctuations have been established. If the most recent sample is very different from previous samples, engineering judgement may be required, and resampling is recommended.

Operations that can affect gas concentration should be identified. For example, venting of sealed main tanks [e.g., 4, pressure relief operation during thermal transits and leaks (sometimes resulting in pressure gauge reading zero)] can lower combustible gas and increase atmospheric gas concentrations. Changes in system parameters could cause variations in reported gas concentrations, for example, load changes. It is often difficult to quantify the effects of these factors compared to the gross changes in reported gas concentrations. Transformer monitoring of gases, moisture, temperatures, load, fans and other parameters can be useful in correlating changes and understanding what may have caused them.

5.3 Context of DGA data interpretation

From an operational point of view, it is important to establish the following priorities:

- a) **Detection:** Detect the generation of any gases that exceed “normal” quantities and utilize appropriate guidelines, so the possible abnormality may be recognized at the earliest possible time to minimize damage or avoid a failure. If this analysis concludes that a fault exists, then proceed with evaluation.
- b) **Evaluation:** Evaluate the impact of an abnormality on the serviceability of the transformer, using a set of guidelines or recommendations. Expert opinion, operator experience, and unit specific conditions should be part of the evaluation.
- c) **Action:** Take the recommended action, beginning with increased surveillance and confirming or supplementary analysis. For example, if a thermal fault is suspected, which may be load sensitive, load reduction (if possible) may help with the diagnosis. If it is not possible, then alternatives, as drastic as removal of the unit from service, may need to be considered. This guide does not cover the procedure required to determine what remedial or operating action may be necessary. This is ultimately the sole responsibility of the transformer owner.

It is useful to look at graphs of gas levels over time (see Annex D) for quick visual detection of suspicious changes, parallel long-term upward rates, or inconsistencies. Whenever a fault is suspected, past and present data should be analyzed and plotted, using one of the methods, such as the Duval Triangles, found in 6.2.3 and Annex D, to see whether there is a consistent pattern or evidence of orderly fault evolution.

The recommended action and resampling interval can be based on the fault diagnosis and the verified DGA status, plus the use of expert judgment. Because of the potentially serious consequences and high cost of misinterpreting transformer test data, an inflexible interpretation, based on an exclusively mechanical scoring approach, without the application of expert judgment, is highly inadvisable.

It is helpful to define DGA status levels to establish sampling intervals and maintenance activities on operational transformers. See 6.1.2 for more information.

- **DGA Status 1:** Screening DGA results are acceptable. Continue routine operation.
- **DGA Status 2:** Incipient or modest recent gas production or moderately elevated gas level. Resample for confirmation and monitor possible gas evolution.
- **DGA Status 3:** High gas levels or continuing significant gas production. Mitigative actions or other responses should be considered (i.e., continuous monitoring).

5.3.1 Initial verification test protocol

When a new transformer is added to a DGA program, or when DGA sampling is resumed for a transformer after several years without sampling, an initial verification is recommended. This is also applicable when there is no prior DGA history for the transformer, or when insulating liquid processing, repairs, or other factors “reset” the transformer’s DGA history. In such cases, there may not be any prior DGA data providing a basis for calculating combustible gas increments or rates of change.

It is suggested to take a sample before and during commissioning procedures and several more samples over a short period of time (a few weeks to a few months) following energization to establish a DGA baseline and ensure that no abnormal gassing is taking place.

For new and repaired transformers, if any of the combustible gas concentrations are above their respective detection limits without a reasonable explanation (such as residual gas from an earlier fault diffusing into the insulating liquid from the paper insulation in a repaired transformer), it may be prudent to schedule

another sample to be taken immediately to check for active gas production. A diagnostic method may be applied to see what the initial sample's pattern of gas concentrations matches, but the diagnosis cannot be considered unless a second sample confirms active fault gas production in a pattern that confirms the diagnosis.

The usual outcome of an initial verification test program would be either the assignment of DGA Status 1 with a recommendation to carry on with DGA periodic screening test protocol per company DGA policy, or the assignment of DGA Status 2 with a recommendation to sample more frequently to check for evidence of change and to discuss the test results with the manufacturer. If a resample confirms an elevated level of gases, contact the manufacturer to review the situation and evaluate the follow-up action.

It is to be noted that typically in an initial verification context, gas level norms lower than Table 1 are used. Often, for new transformers under warranty, the manufacturer will supply its own norms.

See 5.13 of IEEE Std C57.93-2007 for an example of installation sample protocol.

5.3.2 Periodic screening test protocol

Most DGA results fall into this category.

The method of interpreting screening DGA data is explained in 6.1 and in the Figure 2 flowchart. If the DGA status is 1, and there are no apparent reasons for concern, no fault interpretation is necessary, and no special action is needed. The interpretation of the DGA data is complete and the next sample should be taken according to the DGA screening test protocol.

If analysis of a test result produces a DGA status of 2, or if any unusual shift in gas pattern suggests an anomaly, a fault diagnosis should be obtained using a reliable method (see 6.2 and Annex D).

If the fault diagnosis reveals an issue of a low temperature fault (T1), or stray gassing (S), this would be treated as a less urgent issue, however a low temperature fault (T1) may affect the future life of the insulation system.

If there is an indication of high-energy arcing (D2) or a high-temperature thermal fault (T3), or if paper insulation appears to be involved in the fault, another analysis step may be prudent. Some users will consider extra steps with increased surveillance, as recommended for a unit with a DGA status of 3.

If a DGA status of 3 is obtained, then a fault diagnostic and a DGA surveillance test protocol are warranted. See 5.3.3.

5.3.3 Surveillance test protocol

The purpose of the DGA surveillance test protocol is usually either:

- To confirm the absence of suspicious gas activity
- To characterize and diagnose suspicious gas formation
- To provide early warning of dangerous changes or a fault reaching the pre-failure runaway stage

Gas history charts, a stacked chart showing all individual combustible gases, and the Duval Triangles with multiple samples are the most useful graphical tools for surveillance and monitoring.

A short-term rate of increase should be compared with their respective norms to obtain an updated status code. This may be increased if there is evidence of accelerating combustible gas formation. If there is evidence of a fault, a Duval Triangle or pentagon (see 6.2 and Annex D), with all surveillance data plotted on it, can be used to diagnose the fault and to watch for consistency or evolution of the fault type. For example, it could help to see if a thermal fault evolves toward a higher temperature fault.

If the results of a surveillance test indicate a serious or deteriorating situation, it will lead to a Status 3 evaluation. That should lead to consideration of starting a continuous monitoring test protocol, as suggested in 5.3.4.

It may be prudent at this point, that the user consult experts and the transformer manufacturer, as no two transformers are the same. What could be perfectly normal for a given transformer, could be a sign of a dangerous condition in another transformer. In such context, experience from experts is an invaluable tool. See Annex E for additional information.

5.3.4 Continuous monitoring test protocol

The continuous monitoring test protocol should be used when there is a clear indication that the transformer is not operating normally and is generating gas in a significant manner. This protocol should be considered for units with a DGA Status 3, although this should not be automatic. It should be implemented only after a complete review of the DGA results, together with all other available information. Monitoring may be started temporarily until further investigation is completed; or permanently, if the situation is deemed sufficiently serious to warrant it.

In continuous monitoring, the transformer is subjected to frequent sampling and tested at very short, time intervals (e.g., daily or several times per day) for accurate characterization of normal or abnormal gas formation, and very early warning of severely abnormal gas formation. This protocol may lead to the temporary or permanent installation of a suitable on-line monitoring device on the transformer.

The high sampling rate of on-line monitors permits early detection of abnormalities and accurate characterization of rates. Multiple readings may be combined using statistical methods to arrive at improved estimates of the dissolved gas concentrations, and to average over short-term cyclic gassing behavior. Because of the high volume of data generated by on-line monitoring, graphical visualization is essential. Time series graphs with rate values are useful in detection of the onset of increased gassing activity. The technique of plotting DGA results on a Duval Triangle or pentagon is useful in detecting changes in the nature of the fault (see 6.2.3 and Annex D). Also, since rates are obtained in real time over a short period, care should be taken to account for the intrinsic fluctuations of the DGA levels generated by the monitoring process. Gassing rates should be calculated using statistical methods and using trailing data spanning over a long enough time duration to control the likelihood of nuisance gas rate alarms.

In a continuous monitoring test protocol, the various norms used in screening DGA interpretations no longer apply, especially in regard to rates of gas generation. For on-line monitoring, it is not uncommon to use higher rate values than the ones used for laboratory DGA. Each situation is unique.

5.4 Selecting norms values

It is important to understand some of the impacts and limitations of selecting a set of DGA norms for identifying suspicious behavior in a transformer. The choice of 90th and 95th percentiles for norms in this guide is conventional. For some transformer populations other criteria could be chosen based on engineering judgment and local operating and maintenance requirements. The norms shown in Table 1, Table 2, Table 3, and Table 4 were obtained by statistical analysis of a large database of laboratory DGA results. The agglomerated data used to obtain these norms came from several sources in North America, which had notable percentile value differences between themselves. They might not be representative of

what could be obtained with a different data set from different sources or countries. See 6.1.2.5 and Figure A.8 for an example of variability between sources.

It should also be understood that while high-fault gas levels in a transformer suggest an eventful past, gas levels, whether high or not, in themselves are not necessarily a direct assessment of the condition of the transformer, if they are stable. A transformer with twice the gas level of another transformer, is not necessarily twice as likely to fail. On the other hand, active fault gas formation, even with low gas levels, indicates that something might be wrong and may necessitate an investigation or other follow-up activities.

The methodology used in this guide will generate a certain amount of “false positive” cases where extra investigation will simply confirm that there is nothing of concern in the transformer condition. A norm chosen at the 90th percentile (Table 1) will select 10% of all the DGA results for review. Table 3 (95th percentile of Delta) will add about 5% of the DGA results to this. If Table 1 and Table 3 contain values for more than one gas, and that any one gas above a norm is enough to flag the DGA results, it is reasonable to expect that about 40% of all DGA results will need further review. This could be a large number for a major DGA program and should be considered in the implementation of the program. See NOTE 1 below.

In a similar manner, Table 2 uses the 95th percentile as the norm, so it should be expected that 5% of results will exceed these values. If those with an elevated rate of rise are added (Table 4), it is expected that about 20% of the DGA results will be evaluated as Status 3. See NOTE 1 below.

NOTE 1—It should be noted that these values will be true for a large set of DGA results having the same general characteristics as the set used to obtain the norms used in this guide. For smaller sets (for example from a single station), or for notably different DGA populations, a different proportion of selected DGA could be obtained. See Figure A.8 for an example of variations between populations.

This might represent a large investment in time and resources that should be considered by the transformer owner. There is always some trade-off between having too many transformers in normal conditions flagged as “investigate” against the possibility of not detecting a potentially catastrophic condition. If the norms are set too low, excessive investigation will result and faith in the program could be affected. If the norms are set too high, there is an increased possibility of missing a faulty transformer.

Part of the planning and set-up of any DGA program should include deciding what norms to use and which procedure to follow when those norms are exceeded. It is also critical to ensure that sufficient resources are available to handle the level of investigation generated. Transformer owners and operators are strongly encouraged to perform their own study based on their own data, if available, to confirm that the selected norms are adequate for their transformer fleet.

One finding from the analysis of the DGA results (approximately 1.5 million samples) is that certain parameters, most notably the ratio of O₂/N₂ and the transformer age, have a large influence on the typical levels of gases. Other subsets of the data, such as insulating liquid volume, rating, and voltage class, did not produce significant differences, so they were not included.

NOTE 2—The O₂/N₂ ratio was proposed for evaluation as a proxy for distinguishing sealed units from free breathing ones. This approach was used to evaluate the large database where this information was mostly absent, and the break point based on the data suggested the limit of <0.2 or >0.2. An O₂/N₂ ratio ≤ 0.2 is observed in most N₂-blanketed transformers and in about 60% of membrane-sealed ones. An O₂/N₂ ratio > 0.2 is observed in all air-breathing transformers and in about 40% of membrane-sealed transformers. However, it should not be inferred from this approach that by looking at the O₂/N₂ ratio found in a specific sample that it is possible to determine if the transformer is sealed or breathing, as other factors could influence this ratio.

The norms supplied in this document should be considered only as a general guideline based on the best estimate that could be obtained with the data available when this guide was prepared (voluntarily supplied by members of the revision working group, see Annex A). Values in Table 1, Table 2, Table 3, and Table 4 might need to be adjusted to meet specific user requirements or for a specific transformer population.

6. Suggested interpretation procedures for DGA results

6.1 General

This clause describes the process of interpreting a DGA report to obtain a “DGA status” number. However, the DGA status is only one input to the process of determining a transformer’s condition.

There is no direct and infallible method using DGA to obtain an exact evaluation of a transformer’s condition. There are several reasons why the DGA status can be very different from the transformer’s true condition, some of which are as follows:

- a) There are several possible causes of the presence of gas in a transformer. Some of those are related to fault conditions (e.g., arcing, overheating, PD), others are related to more benign conditions (e.g., stray gassing, contamination, previous fault now inactive, and mild core overheating [B96]).
- b) Some pre-failure conditions simply do not generate gas. (e.g., mechanical or insulating system weakness).
- c) Some normal conditions do generate gases. (e.g., normal aging, and insulating liquid oxidation).
- d) The DGA data used to develop this procedure and norms came from in-service transformers for which their condition information (faulty or not) at the time of the DGA was unavailable. Therefore, there was no possibility to directly correlate one with the other, only to evaluate the DGA results distribution assuming most of the data came from healthy transformers.

Therefore, the methodology presented here will classify the DGA results, not the transformer condition. Users should not equate “DGA status” to “transformer condition.” It could be presumed that one is possibly related to the other, but there can be no guarantee in this respect. Transformers could fail without any prior gas generation, while others could be operating with high levels of gases.

This guide classifies DGA results into 3 groups, “DGA Status 1,” “DGA Status 2,” and “DGA Status 3,” using three tables of norms, as follows:

- DGA Status 1: Low gas levels and no indication of gassing. (Unexceptional DGA)
- DGA Status 2: Intermediate gas levels and/or possible gassing. (Possibly suspicious DGA)
- DGA Status 3: High gas levels and/or probable active gassing. (Probably suspicious DGA)

Table 1 and Table 2 define low (below Table 1), intermediate (between Table 1 and Table 2), and high (above Table 2) gas levels. Table 3 defines possible gassing. Table 4 defines probable active gassing.

Other DGA interpretation procedures exist and the method used in this guide should not be considered the only possible procedure. For an example of an alternative approach, see Annex F and H.2.3. When an increase in gas levels is detected, most users will tend to assume that there is an active fault within the transformer. However, before beginning the process of trying to confirm its existence and identify its cause, it is advisable to review the material in 5.1 and 5.2. The possibilities identified there should be investigated before any action is taken to remove a transformer from service for further investigation, maintenance, or replacement. A valid interpretation of DGA results can begin only after a data quality review, to identify and correct possible data quality problems, has been performed. It is also important to consider that a review of data cannot necessarily identify all possible data quality issues. Therefore, when surprising or alarming results are obtained, it is highly advisable to collect and process another sample to confirm results.

6.1.1 DGA interpretation procedure

After data quality and confirmation issues have been addressed, interpretation of the DGA data can be undertaken. Prior DGA results should be used for characterization of increments and rates. If abnormal DGA results are found, any available supplementary information, such as test and maintenance records, load data, environmental conditions, etc., should be consulted for possible clues as to the origin and nature of the abnormalities. Comparison of DGA data from sister units, i.e., transformers built to similar specifications, is useful for spotting unusual results and for revealing common patterns, which may provide a better understanding of the data.

Figure 2 is a flow chart that provides a suggested process to review the DGA results.

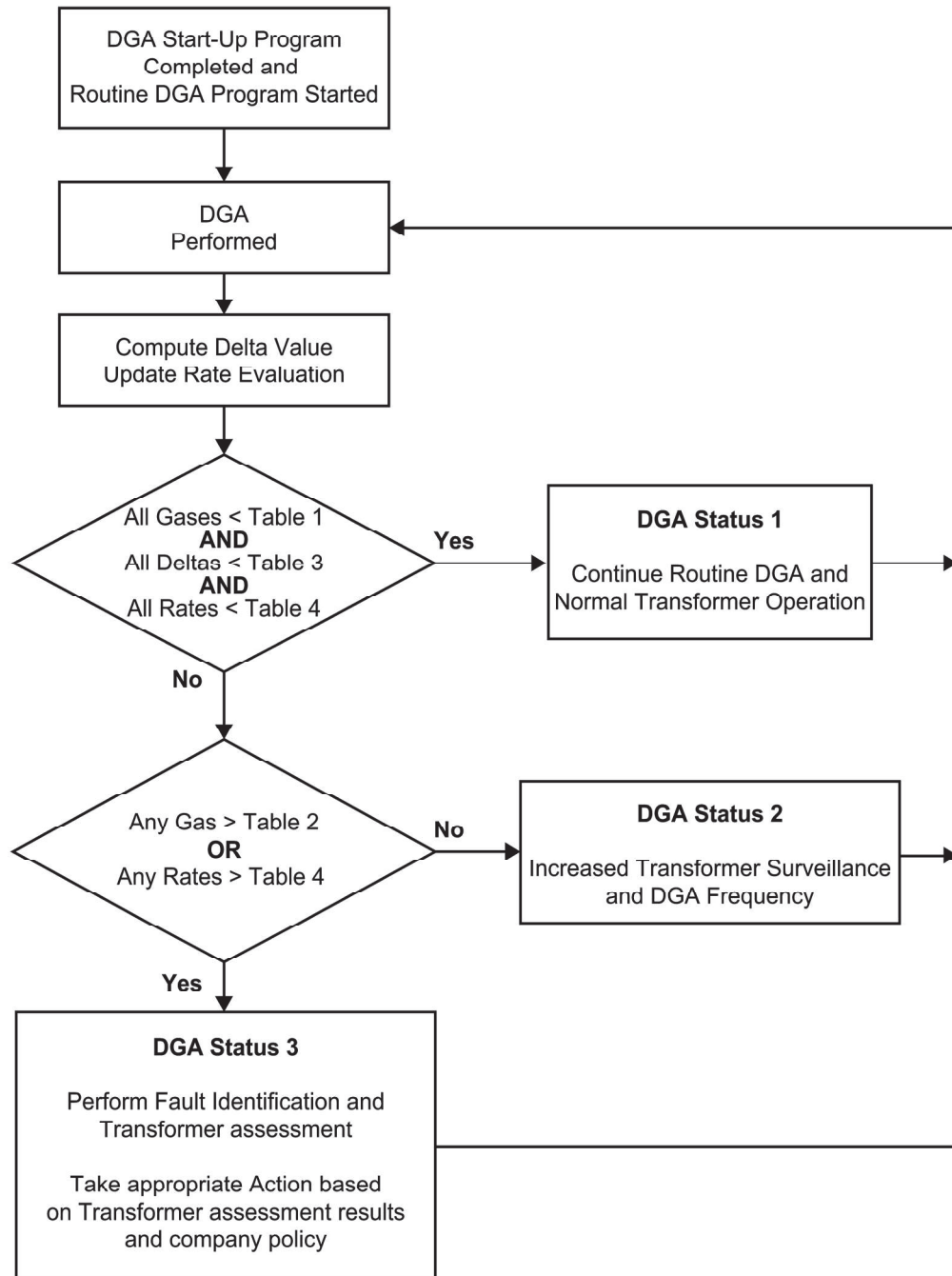


Figure 2—DGA interpretation flow chart (see 6.1 and 6.1.2 for status definition)

Table 1 is based on the 90th percentile of the population of DGA results (gas levels).

Table 2 is based on the 95th percentile of the population of DGA results (gas levels).

Table 3 is based on the 95th percentile of deltas between two consecutive laboratory DGA results [Δ $\mu\text{L/L}$, (Δ ppm)], without any adjustment due to time (no normalization per year). This is dominated principally by DGA result fluctuations caused by the analysis process itself. Table 3 is used to decide when a difference between the latest DGA result and the previous one is above the normal DGA fluctuations and might indicate a gas increase. In such cases, a confirmation sample is suggested.

Table 4 is based on 95th percentile of rate computed with multi-point (3 to 6) linear regression [$\mu\text{L/L/year}$ (ppm/year)]. As the number of points increase, fluctuations caused by the laboratory DGA analysis process cancel each other (average out), and this table is dominated principally by transformer gas evolution. Table 4 is used to decide when a sequence of DGA results indicates probable active gassing.

The following procedure explains the Figure 2 flowchart and refers to Table 1 through Table 4 in 6.1.3.

- Step 1: After completion of a start-up DGA program (see 5.3.1), periodic DGA are performed as per company routine policy.
- Step 2: Compute the O_2/N_2 ratio. Compute the absolute variation [$\Delta \mu\text{L/L}$ (ppm)] for each gas from the previous routine sample. Update multipoint rate values using the last 3 to 6 data points over the last 4 to 24 mo period, if available. If more than 6 data points are available, use the six most recent data points, not exceeding two years, to compute the rates.

NOTE—Rates will not be available if the transformer is sampled only once per year.

- Step 3: If age is known, compare all gas values to the applicable column of Table 1, according to the O_2/N_2 ratio and age. If age is unknown, use the values in the column “Unknown” (under “Transformer age year header) of the applicable table. If the O_2/N_2 ratio is not available, the O_2/N_2 ratio >0.2 section should be used.

NOTE—When the O_2/N_2 ratio is near 0.2, it could happen that successive DGA test results change back and forth between <0.2 and >0.2 due to intrinsic DGA variability. In such cases it is recommended to use the >0.2 section.

- Step 4: If all gas levels are below the applicable values in Table 1, compare the delta values to the applicable sections of Table 3. Compare rate values to the applicable sections of Table 4, if available.
 - Step 4a: If all gas delta values are below the applicable section of Table 3, and all rates values are below the applicable section of Table 4 (if available), then a DGA status of 1 is indicated. Continue routine sampling as per company policy. See 6.1.2.1.
 - Step 4b: If any delta is greater than the value in the applicable sections of Table 3, or any calculated generation rate is greater than the applicable sections of Table 4, perform a confirmation DGA within a month and then perform Step 4c.
 - Step 4c: Compute the absolute variation (delta) between the reference sample (the one used as reference in Step 4b) and the confirmation sample. Compute rates with the confirmation sample replacing the previous value.
 - Step 4d: If the confirmation sample does not indicate an increase from the previous sample (i.e., all gas variations delta are below the applicable section of Table 3 and all rates below the applicable section of Table 4 norms), and all gas level values are also still below the applicable section of Table 1, DGA status is 1. Continue routine sampling per the company policy or manufacturer requirements. See 6.1.2.1.
 - Step 4e: If the second sample confirms an increase (Delta) has occurred but all gas level values are below the applicable section of Table 1 and all multi-point rates are below the applicable section of Table 4 values, then a DGA status of 2 is indicated. See 6.1.2.2.

- Step 5: If any one gas level is between the values in the applicable sections of Table 1 and Table 2 with no gas levels above the applicable sections of Table 2, and all multi-point rates are below the applicable section of Table 4, then a DGA status of 2 is indicated. See 6.1.2.2.

If only 1 sample per year is taken, there will not be enough samples to calculate the multipoint gas generation rates for comparison to Table 4, so only Table 3 would be used in such cases. If Table 3 values are exceeded, a confirmation sample is required, which will allow the computation of the rates (e.g., 3 samples in 2 years).

- Step 6: If any one gas level is above the applicable section of Table 2, or if any rate is above the applicable section of Table 4, a DGA status of 3 is indicated. See 6.1.2.3.
- Step 7: For DGA in status 3, gas evolution should be monitored for a significant period of time. If during that period of time there is no significant positive rate observed, then a lower DGA status could be considered, after consultation with a DGA expert. See 6.1.2.3.
- Step 8: For extremely high concentrations, deltas, or rates, consult a DGA expert. See 6.1.2.4.

See B.2, B.3 and B.4 for examples of the application of this procedure.

6.1.2 DGA status

The classification process and recommendations below are based on gas levels and level variation norms obtained from a statistical analysis of a large population of DGA results (90th and 95th percentiles). This procedure is a guideline only and should not preclude any specific company policy or prudent management. See 5.4.

6.1.2.1 DGA Status 1

Transformers with DGA Status 1 are considered as probably normal, per DGA results statistics. Routine DGA and insulating liquid testing should be performed per the owner's internal policy or manufacturer's recommendations. Normal transformer operation can be continued.

6.1.2.2 DGA Status 2

Transformers with DGA Status 2 are considered as possibly suspicious and warrant additional investigation. Possible causes of gas generation using DGA should be investigated. If the fault diagnosis reveals an issue of Partial Discharges (PD), low temperature fault (T1), or stray gassing (S), this would be treated as a less urgent issue, but still may affect future life of the insulation system.

Otherwise, increased sampling frequency should be maintained or started. On-line dissolved gas monitoring may also be considered. Establishing multi-point rates is recommended if not already available.

Transformers having a DGA Status 2 due only to gas levels exceeding the values in Table 1 (especially if the only high levels are for carbon oxides), could be reassigned to routine sampling if there is no sign of active gassing during a year or more of increased sampling frequency (all samples below Table 3 and Table 4).

6.1.2.3 DGA Status 3

Transformers with DGA Status 3 are considered as probably suspicious. On-line dissolved gas monitoring may be considered if close monitoring is necessary. Probable causes of gas generation using DGA interpretation procedures (see 6.2 and Annex D) should be investigated. The transformer should be placed under increased surveillance and additional transformer testing is recommended. Consultation with the transformer manufacturer or a transformer expert is also recommended. If after complete review of the available information, the transformer condition is deemed acceptable for continuous operation, then it is suggested to simply maintain surveillance typical of a lower DGA status. An example of this would be a transformer having a DGA Status 3 due only to gas levels exceeding the values in Table 2 (especially if the only high levels are for carbon oxides) when several samples taken over a year or more indicate no sign of active gassing (all samples below Table 3 and Table 4).

6.1.2.4 Extreme DGA results

As mentioned in Clause 1, in many cases, active faults generate gases at such a high rate that detection and assessment do not require finesse, or significant work. Gas levels or changes that are much larger than those provided in Table 2 and Table 3 warrant immediate extra investigation, which may include additional oil analysis and physical or electrical testing. Internal inspection might be considered if a confirmation sample rules out sampling error and fault interpretation indicates a possible cause that can be visually observed. For example, if an increase in C_2H_4 of 200 $\mu\text{L/L}$ (ppm) or a level of C_2H_6 of 1000 $\mu\text{L/L}$ (ppm) is observed, these would be considered extreme. In such cases, immediate investigation and operating restrictions should be initiated, at least until the cause of the large value is either dismissed as “erroneous” (sampling error for example) or fully understood and the unit has been deemed acceptable for continued operation. In all cases, expert opinion, operator experience, and specific unit conditions should be part of the evaluation. See B.4 for an example.

6.1.2.5 Caution in establishing and using DGA status value

Norms based on statistics should be considered as indicative only. It should not be taken for granted that a transformer is operating properly, simply because its gas levels are below norms. It can only be assumed that there is simply a lack of DGA evidence of abnormality. Likewise, a transformer with DGA Status 2 or Status 3 (i.e., being above statistical norms) is not necessarily faulty. It can only be concluded that its behavior is somewhat unusual and warrants additional investigation and/or precautions to be implemented, either simple or extensive, as evaluated by the DGA expert.

During the study to obtain the norm values, it was observed that large variations of results (percentiles) occurred between various sources, see Annex A for an example (this was also observed in other studies). Gas levels are a function of many parameters, not all of them understood or known. For example, variations in load pattern, geographical location, manufacturing process, maintenance practice, vintage, type of insulating liquid, rating, voltage class, or type of transformer could result in different gas levels and statistics. It is important to realize that these variations could be very large between sources (factors more than 2 to 1 have been observed) and affect the results of the interpretation process presented here. The information on these parameters that could have possibly been used in the study to refine the results was often simply not available or unreliable. For these reasons, numbers in Table 1 through Table 4 have been rounded to at most two significant digits and should not be considered, at any time, as “universal,” “absolute,” “authoritative,” or “immutable” references. Transformer owners and operators are strongly encouraged to perform their own study based on their own data when available. See Annex A.

In some cases, it has been observed that transformers with an energized load tap changer may have some insulating liquid leakage from the tap changer compartment into the main tank. In such cases, some of the gases (especially C_2H_2 and C_2H_4) would be considerably higher than the value in Table 1 and Table 2. This could be interpreted as an internal fault, rather than just a leak. The apparent gassing will continue until the

leak is repaired, and the remnant gases will remain in the main tank until the transformer insulating liquid is vacuum processed.

DGA is a powerful tool to detect anomalies in transformers. However, it is not the only tool available to transformer owners. The use of DGA results to monitor transformers should not be assumed to be a replacement for other prudent operating, management, and monitoring practices. This is especially true of a transformer assessment following the detection of an anomaly. Conclusions or actions should never be based exclusively on a single DGA results.

6.1.3 DGA status norms

DGA status norms are shown in Table 1 through Table 4:

Table 1—90th percentile gas concentrations as a function of O₂/N₂ ratio and age in μL/L (ppm)

		O ₂ /N ₂ Ratio ≤ 0.2				O ₂ /N ₂ Ratio > 0.2			
		Transformer Age in Years				Transformer Age in Years			
		Unknown	1 – 9	10 – 30	>30	Unknown	1 – 9	10 – 30	>30
Gas	Hydrogen (H ₂)	80	75		100	40	40		
	Methane (CH ₄)	90	45	90	110	20	20		
	Ethane (C ₂ H ₆)	90	30	90	150	15	15		
	Ethylene (C ₂ H ₄)	50	20	50	90	50	25	60	
	Acetylene (C ₂ H ₂)	1	1			2	2		
	Carbon monoxide (CO)	900	900			500	500		
	Carbon dioxide (CO ₂)	9000	5000	10000		5000	3500	5500	

NOTE—During the data analysis, it was determined that voltage class, MVA, and volume of mineral oil in the unit did not contribute in significant way to the determination of values provided in Table 1.

Table 2—95th percentile gas concentrations as a function of O₂/N₂ and age in μL/L (ppm)

		O ₂ /N ₂ Ratio ≤ 0.2				O ₂ /N ₂ Ratio > 0.2			
		Transformer Age in Years				Transformer Age in Years			
		Unknown	1 – 9	10 – 30	>30	Unknown	1 – 9	10 – 30	>30
Gas	Hydrogen (H ₂)	200	200			90	90		
	Methane (CH ₄)	150	100	150	200	50	60	30	
	Ethane (C ₂ H ₆)	175	70	175	250	40	30	40	
	Ethylene (C ₂ H ₄)	100	40	95	175	100	80	125	
	Acetylene (C ₂ H ₂)	2	2		4	7	7		
	Carbon monoxide (CO)	1100	1100			600	600		
	Carbon dioxide (CO ₂)	12500	7000	14000		7000	5000	8000	

NOTE—During the data analysis, it was determined that voltage class, MVA, and volume of mineral oil in the unit did not contribute in significant way to the determination of values provided in Table 2

Table 3— 95th percentile values for absolute level change between successive laboratory DGA samples in $\mu\text{L/L}$ (ppm)

		Maximum $\mu\text{L/L}$ (ppm) variation between consecutive laboratory DGA samples	
		O_2/N_2 Ratio ≤ 0.2	O_2/N_2 Ratio > 0.2
Gas	Hydrogen (H_2)	40	25
	Methane (CH_4)	30	10
	Ethane (C_2H_6)	25	7
	Ethylene (C_2H_4)	20	
	Acetylene (C_2H_2)	Any Increase	
	Carbon monoxide (CO)	250	175
	Carbon dioxide (CO_2)	2500	1750

NOTE—Contribution of voltage class, MVA, and volume of mineral oil in the unit was not studied for Table 3 as they have not been retained for Table 1 and Table 2. Data was insufficient to study age influence.

Table 4—95th percentile values from multi-points (3-6 points) rate analysis of laboratory DGA samples with all gas levels below Table 1 values, in $\mu\text{L/L/year}$ (ppm/year)

		Maximum $\mu\text{L/L/year}$ (ppm/year) rate in function of the period between first and last point of the laboratory DGA series (3 to 6 samples)			
		O_2/N_2 Ratio ≤ 0.2		O_2/N_2 Ratio > 0.2	
		Period between first and last point of the series			
		4-9 Months	10-24 Months	4-9 Months	10-24 Months
Gas	Hydrogen (H_2)	50	20	25	10
	Methane (CH_4)	15	10	4	3
	Ethane (C_2H_6)	15	9	3	2
	Ethylene (C_2H_4)	10	7	7	5
	Acetylene (C_2H_2)	Any increasing rate		Any increasing rate	
	Carbon monoxide (CO)	200	100	100	80
	Carbon dioxide (CO_2)	1750	1000	1000	800

NOTE—Contribution of voltage class, MVA, and volume of mineral oil in the unit was not studied for Table 4 as they have not been retained for Table 1 and Table 2. Data was insufficient to study age influence.

See 5.4 for general considerations on the selection of norm values.

See Annex A for a description of the methodology used to produce the numbers provided in Table 1, Table 2, Table 3, and Table 4.

6.1.4 Impact of DGA limitations

Norm values used in this guide have been obtained from a statistical study of DGA results supplied by several utilities and laboratories. DGA is a complex analytical process, and as such it has some limitations

that are important to consider for avoiding erroneous interpretation. Precautions for identifying faulty results before interpretation are outlined in 5.1 and 5.2. However, even when there is no error in the DGA process itself, some of the DGA intrinsic limitations have an impact on the selection and use of norms.

It is generally recognized by the industry experts that increasing gas levels are more of a concern than the levels themselves. Therefore, it is important to have some guidelines on acceptable gas generation rates.

However, the work performed in the analysis of laboratory DGA results indicated that obtaining a meaningful evaluation of the gassing rates requires more than the common practice of using two consecutive DGA to compute a yearly rate. Instead, this guide uses two different tables [Table 3 (delta without normalization) and Table 4 (multi point rates)] to evaluate the gassing tendency of a DGA set to overcome the effect of normal random fluctuations of the DGA process. See B.1 for a more detailed explanation of the why and how of this process.

It is also recognized that all faults are not of the same concern, so the type of fault should also be considered, not just the gas levels or the gas evolution.

As DGA interpretation is still more of an art than a science, the consultation of a transformer expert with DGA interpretation experience is strongly encouraged.

6.2 Fault type identification from DGA results

Since the introduction of DGA in the 1960s, several methods of interpretation have been developed. The large number of these methods, and the fact that some of them are specific to the utility that introduced them, precludes the presentation of all of them in this guide. Two common methods (Rogers Ratios and Duval Triangle 1) are presented in this clause. Additional methods are presented in Annex D. Fault nomenclature and descriptions are presented in Annex C.

6.2.1 General

All fault identification methods (Rogers Ratios, Doernenburg Ratios, Key gas, Duval Triangles 1-4-5 and Pentagons 1-2) can be used only if $\mu\text{L/L}$ (ppm v/v) values are reliable and accurate enough. Guidelines as to when the accuracy of DGA results should be verified and guidelines as to when fault identification methods should be used or not are given in 5.2.1.

Hydrogen (H_2) is created primarily from corona partial discharge and stray gassing of oil, also from sparking discharges and arcs, although C_2H_2 is a much better indicator in such cases. It can also be caused by chemical reaction with galvanized steel.

Methane (CH_4), Ethane (C_2H_6), and Ethylene (C_2H_4) are created from heating of oil or paper.

Acetylene (C_2H_2) is created from arcing in oil or paper at very high temperatures above $1000\text{ }^\circ\text{C}$. Transformers without internal fuses, switches or other arcing devices that may have operated should not create any C_2H_2 under normal operating conditions. It is not uncommon to find increased levels of H_2 or C_2H_4 when C_2H_2 is detected.

The ranges of temperatures where these gases are mostly produced in oil can be seen in Figure 1. It can also be seen in Figure 1, that mixtures of these gases are always formed at any temperature. By looking at their relative proportions in oil, it is possible to identify the faults that have produced them, using one of the methods described in 6.2 or Annex D.

Carbon Monoxide (CO) and Carbon Dioxide (CO_2) are created from heating of cellulose or insulating liquid.

6.2.2 Rogers Ratios Method

The Rogers Ratios Method is summarized in Table 5. It uses three gas ratios indicating five different types (cases) of faults, depending on the values of the ratios in column 2 through column 4 of Table 5.

Table 5—Rogers Ratios Method

Case	C_2H_2/C_2H_4	CH_4/H_2	C_2H_4/C_2H_6	Suggested fault diagnosis
0	< 0.1	0.1 to 1.0	< 1.0	Unit normal
1	< 0.1	< 0.1	< 1.0	Low-energy density arcing—PD ^a
2	0.1 to 3.0	0.1 to 1.0	> 3.0	Arcing—High-energy discharge
3	< 0.1	0.1 to 1.0	1.0 to 3.0	Low temperature thermal
4	< 0.1	> 1.0	1.0 to 3.0	Thermal < 700 °C
5	< 0.1	> 1.0	> 3.0	Thermal > 700 °C

^a There is a tendency for the ratios C_2H_2/C_2H_4 and C_2H_4/C_2H_6 to increase to a ratio above 3 as the discharge develops in intensity.

The limitation of the Rogers Ratios Method is that it cannot identify faults in a relatively large number of DGA results (typically 35%), because they do not correspond to any of the cases in column 1 of Table 5, even when $\mu\text{L/L}$ (ppm) values are high and there is obviously a fault.

6.2.3 Duval Triangle 1

The Duval Triangle 1 Method is illustrated in Figure 3:

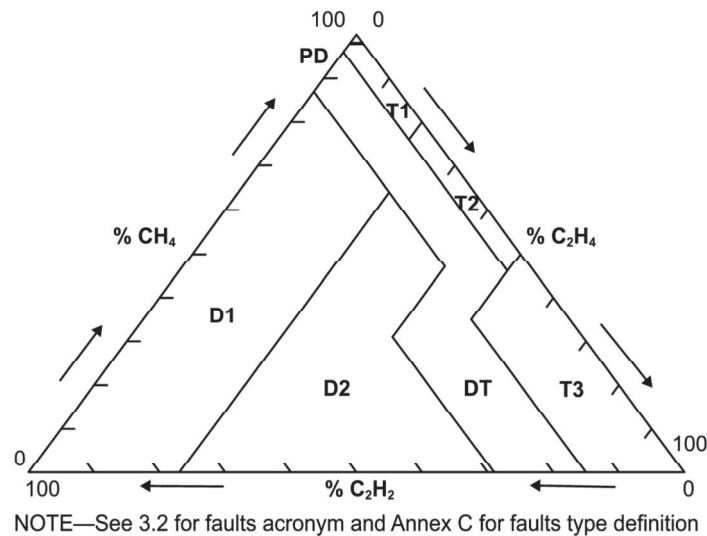


Figure 3—Duval Triangle 1 Method

The Duval Triangle 1 Method uses three gases corresponding to the increasing energy content or temperature of faults: methane (CH_4) for low energy/ temperature faults, ethylene (C_2H_4) for high temperature faults, and acetylene (C_2H_2) for very high temperature/energy/arcing faults. On each side of the triangle are plotted the relative percentages of these three gases.

This method allows identification of the six basic types of faults indicated in Annex C.1, plus mixtures of electrical/ thermal faults in zone DT. Table 6 gives the numerical values for fault zone boundaries of Duval Triangle 1 Method expressed in ($\%CH_4$), ($\%C_2H_4$), and ($\%C_2H_2$).

Table 6—Fault zone boundaries for Figure 3

Gas% / Fault	% CH ₄	% C ₂ H ₄	% C ₂ H ₂
PD	≥ 98	—	—
T1	< 98	< 20	< 4
T2	—	≥ 20 and < 50	< 4
T3	—	≥ 50	< 15
DT	—	< 50	≥ 4 and < 13
	—	≥ 40 and < 50	≥ 13 and < 29
	—	≥ 50	≥ 15 and < 29
D1	—	< 23	≥ 13
D2	—	≥ 23	≥ 29
	—	≥ 23 and < 40	≥ 13 and < 29

NOTE 1—See 3.2 for fault acronyms and Annex C for fault type definitions.

The procedure for calculating and displaying DGA points in Duval Triangle 1 are in D.4.¹⁰

NOTE 2—For a more detailed interpretation of fault types PD, T1, T2 and T3, see Annex D, Duval Triangles 4 and 5, and Duval Pentagons 1 and 2.

The advantages of the Duval Triangle 1 Method are that it always proposes a fault identification (it is a “closed” system as compared to 2-gas ratios methods), with few erroneous diagnosis (it is based on a large number of inspected cases of faulty transformers in service), and it allows the ability to visually and rapidly follow the evolution of faults with respect to time in a transformer. Conversely, because it always gives a diagnostic, it should be used only to identify a fault when other information indicates that a fault is likely to exist. The fact that a possible fault type is identified is not in itself a confirmation of the presence of a fault.

The Rogers Ratio Method and Duval Triangle 1 Method should not be used on samples with very low gas levels, which can be unreliable and inaccurate. See 5.2 for further information.

¹⁰ Free algorithms for using the Duval Triangles Methods are available in the IEEE Std C57.104-2019 directory located at: https://standards.ieee.org/content/dam/ieee-standards/standards/web/download/C57.104-2019_downloads.zip.

Annex A

(informative)

Data research and findings

A.1 Data collection and preparation

The purpose of this annex is to present a historical synopsis of the efforts of the IEEE Std C57.104 Guide Working Group, and specifically those efforts of the Data Task Force (DTF). The DTF has presented the details of the data analysis, to the extent possible, without causing any jeopardy or harm to any of the commercial entities who provided data to the WG for study and analysis. These details include the total number of data sets collected; the total number of data sets used; the methods used by the DTF to identify and cull outliers, bad data, or erroneous inputs; the statistical analysis methods used and the findings of the analyses; assumptions made and the logic used to make them; final presentation of data tables and statistical norms.

The task of revising and updating a guide on DGA interpretation began with accumulating a large data base of recent DGA results. Older revisions of the guide and methods of interpretation utilized DGA result datasets which were no longer available, and the size and scope of them were not well known. As such, the first task for this Working Group was to accumulate a new dataset. This new dataset would be based on relatively recent data from known sources, current methods of insulating liquid sampling, and current methods of laboratory analysis of the dissolved gases. The dataset is sufficiently large, and from a variety of data sources, to remove all doubt of statistical bias.

The Working Group requested voluntary DGA data contributions from transformer end-users (electrical utilities) and laboratories. Contributors provided data voluntarily, on good faith that the data would be utilized only for the purposes of writing this revised guide. The new raw dataset (“raw” meaning prior to any data elimination) contained more than 1 500 000 individual DGA results. In addition to the dissolved gas concentrations, as many of the following variables as possible were requested to accompany each individual DGA result: insulating liquid type (request was made to supply only data for mineral oil-immersed transformers); equipment type; transformer type; number of phases; MVA; voltage; age; manufacturer or; serial number or identification number; preservation system; insulating liquid volume; weight; sampling date; and analysis date.

The approach was to gather as much information as possible about each sample, which could potentially prove useful during the forthcoming data analysis and interpretation. Indeed, having some of the above information for each sample was essential during the initial “clean up” of the raw dataset.

With the raw dataset in hand, the data “clean up” process began. The primary goal of this process was to discard any data points deemed inapplicable or unreliable, resulting in a processed or “clean” dataset comprised of high quality data. Having a large raw dataset to begin with allowed a strict protocol of filtration.

Some of the data points were discarded for lack of essential information such as: gas concentration, liquid type, valid sample date and unique identifier.

Additional data was discarded for the following reasons:

- Equipment Type: Some of the DGA results did not belong to transformers but to load tap changers, storage tanks, or other equipment.

- Operational Status: For the relatively few transformers which provided this information, the data point was discarded if the sample came from a transformer that was known not to be in service.

Upon completing the above process, further filtering of the dataset was applied to eliminate duplicate results; defined as two DGA results with the same ID and the same analysis date.

Next, corrections were made to some of the data points due to incorrect use of units associated with two data variables; these two variables were MVA and kV. Some DGA records could be corrected by examining other accompanying variables such as insulating liquid volume and transformer type. While these corrections were cumbersome, this was necessary so as to not discard or misuse a disproportionate number of large or small transformers in the dataset. Alternatively, when size was recorded in values of 1000 MVA or larger, and there was no other accompanying information to judge otherwise, the size was changed to kVA, with the understanding that there could be a very small error introduced for the rare case when the transformer was indeed 1000 MVA or larger. The same operation was performed for kV.

Finally, the processed dataset was made anonymous by compiling the data from all contributors together, removing contributor names, and replacing transformer serial numbers or identifiers with generic identifiers.

Following preparation of the data, the data was analyzed to obtain percentile values as a function of several criteria for diverse sub-populations (age, rating, O₂/N₂ ratio, etc.). Those values were used to prepare Table 1, Table 2, Table 3, and Table 4.

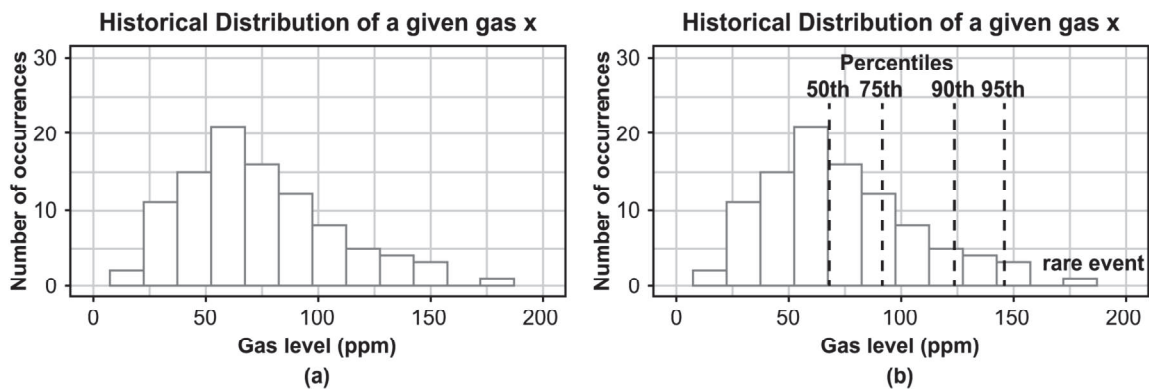


Figure A.1—Example of population distribution and percentile

Figure A.1(a) is an illustration of a generic historical distribution of a given gas x, heavily skewed to the right. Looking at the distribution, most of the time the gases are concentrated on the lower end (left side of the distribution), but there are a few samples that do occur on the higher end (e.g., above the 90th percentile).

Figure A.1(b) is an illustration of the relative location of “typical” percentiles used in multiple industries. The same concept may be applied to distributions skewed to the left or to normal distributions. Although there are several formulas to calculate percentiles, the concept is very straightforward and simply requires a calculation of the given percentage (e.g. 90th percentile or the 90% limit) of the numerically ordered data in ascending order.

The 90th percentile is commonly used to indicate the “norm” of a given parameter since it encompasses a large majority of the data and only leaves out 10% of the distribution. Note, that while there was no rounding up or rounding down of any figures in the processed dataset, some of the results from data analysis were rounded in the presentation of the results. To not round the result would imply a level of

accuracy which did not exist. The presentation of the 90th and 95th percentile values for dissolved gas concentrations, deltas and rates were rounded as follows:

The following rounding scheme was used for Table 1, Table 2, Table 3, and Table 4.

1 to 10:	Unit	500 to 1000:	Nearest 100
10 to 50:	Nearest 5	1000 to 2500:	Nearest 250
50 to 100:	Nearest 10	2500 to 5000:	Nearest 500
100 to 250:	Nearest 25	Above 5000:	Nearest 1000
250 to 500:	Nearest 50		

In addition to the rounding, adjacent numbers in Table 1, Table 2, Table 3, and Table 4 have been agglomerated in single value when they differed by less than 35%.

A.2 Dataset characteristics

The dataset used to generate the values in Table 1, Table 2, Table 3, and Table 4 had the following characteristics:

- Number of data suppliers: 18 (some sources have been broken by regions)
- Total number of DGA analysis: 1 391 436
- Total number of Transformers: 313 076
- Total number of DGA results supplied with transformer age information: 618 715
- Total number of DGA results supplied with transformer rating information: 738 188

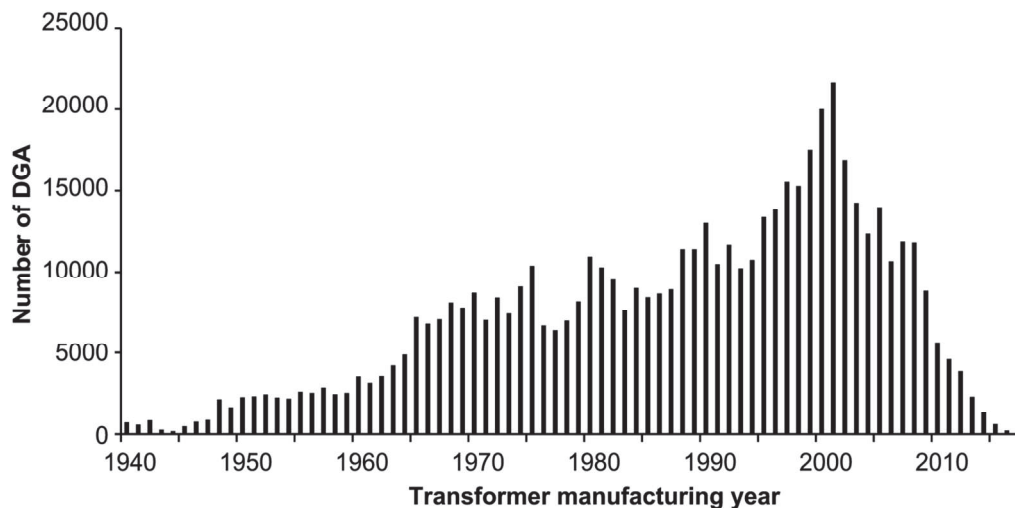


Figure A.2—Distribution of DGA in function of transformer manufacturing year

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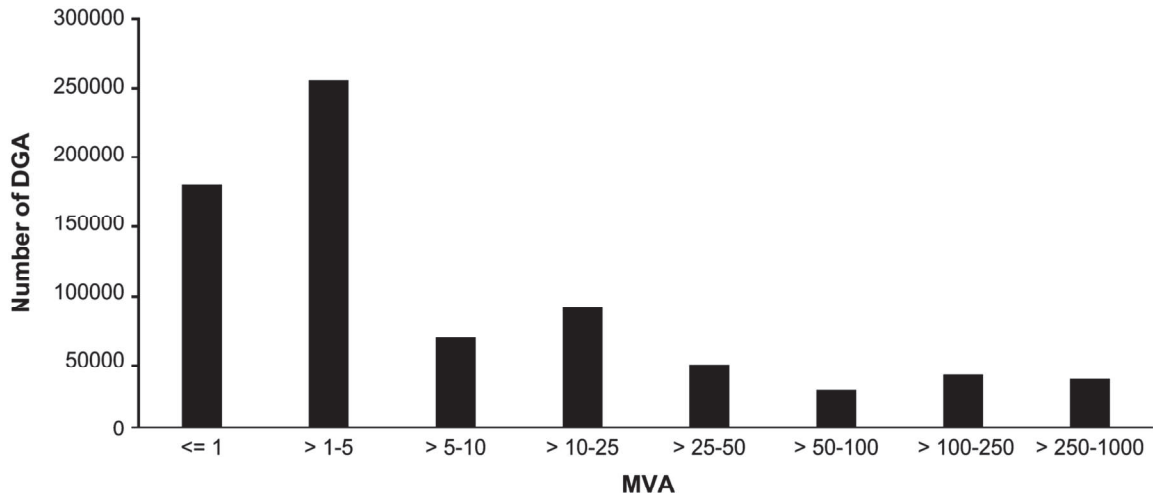


Figure A.3—Distribution of DGA in function of transformer rating

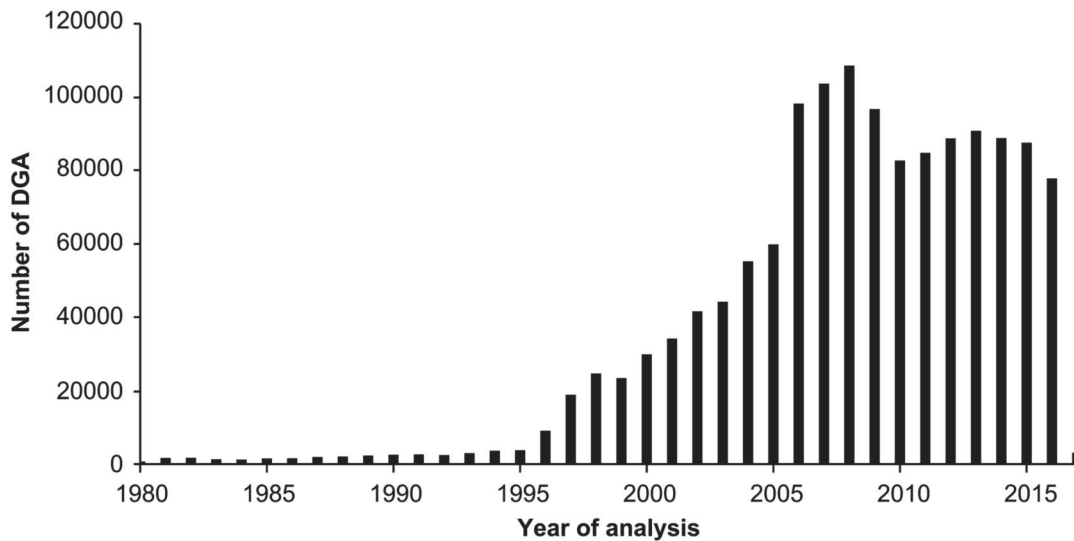


Figure A.4—Distribution of DGA in function of year of analysis

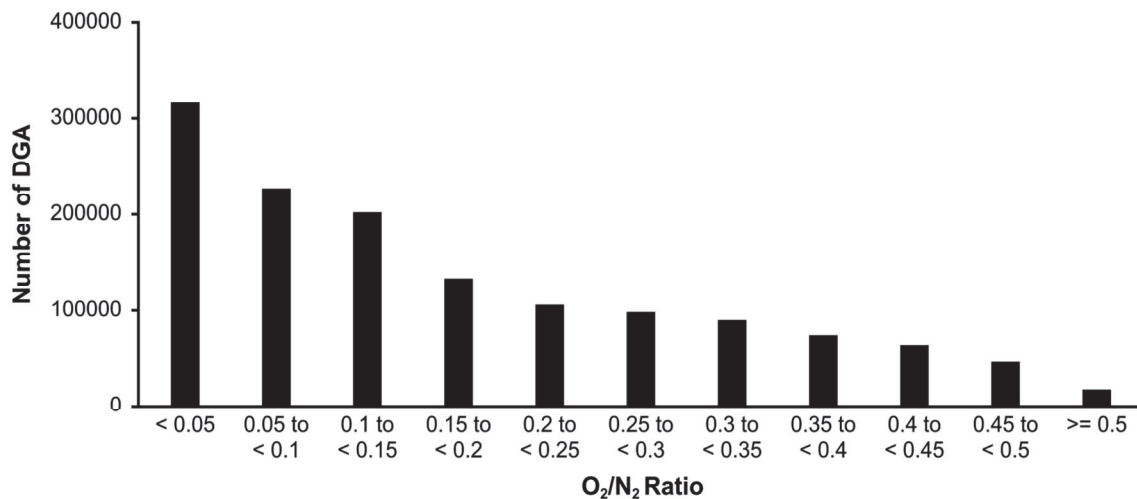


Figure A.5—Distribution of DGA in function of O₂/N₂ ratio

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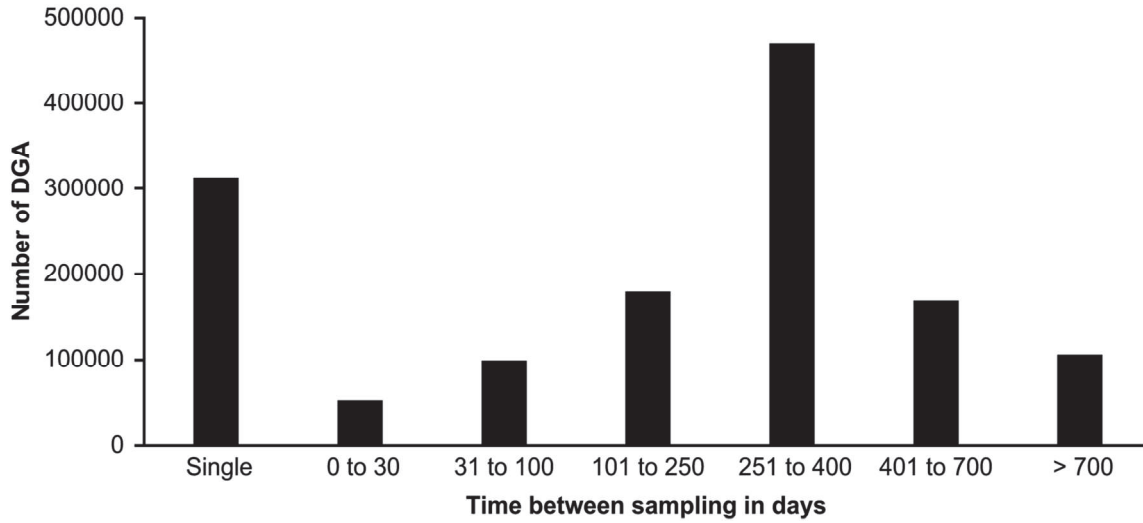


Figure A.6—Distribution of DGA in function of time between sampling

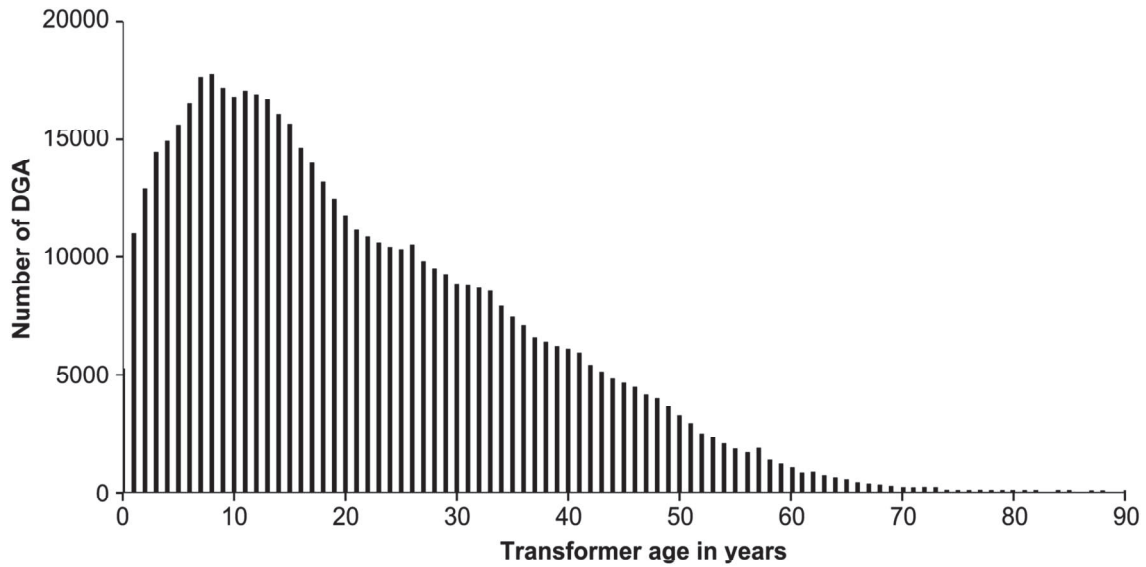


Figure A.7—Distribution of DGA in function of transformer age at the time of sampling

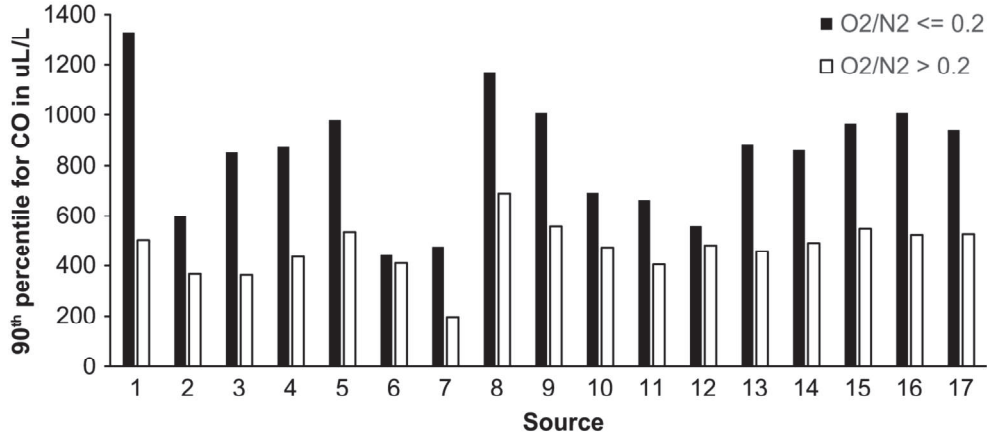


Figure A.8—Example of the variations of percentile values observed between the different DGA dataset sources (90th percentile for CO)

Table A.1—Distribution of DGA in function of O₂/N₂ ratio and age

	O ₂ /N ₂ ≤ 0.2				O ₂ /N ₂ > 0.2			
	Age in years							
	All	1 to 9	10 to 30	> 30	All	1 to 9	10 to 30	> 30
Number of DGA	876 314	84 215	179 829	113 264	495 561	59 320	86 983	72 039
% of DGA	63.0%	6.1%	12.9%	8.1%	35.6%	4.3%	6.3%	5.2%

NOTE—The columns labeled “All” include all DGA results with valid O₂ and N₂ values (98.6% of the data received, after removal of DGA due to other invalid data), independent of the “Age” information. The columns labeled “1 to 9”, “10 to 30” and “>30” contain only the DGA results supplied with valid Age (excluding Age < 1 year), O₂ and N₂ values.

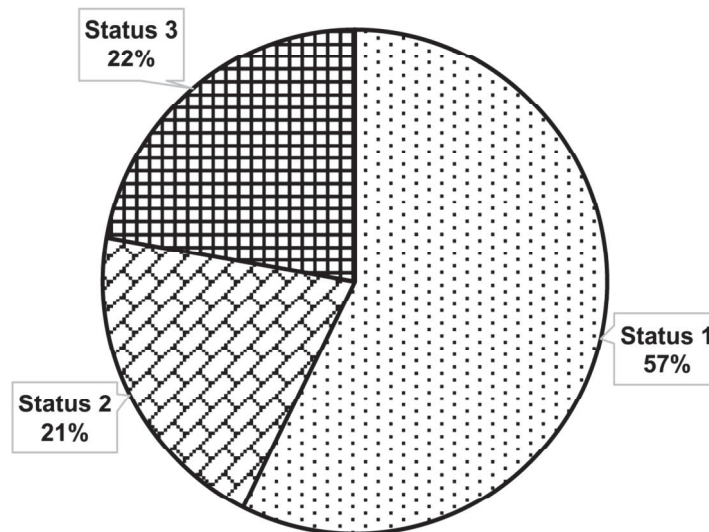


Figure A.9—Distribution of DGA status in the study dataset

A.3 Future work

The procedure to interpret DGA results presented in this guide is, by its very nature, a work in progress.

Progress in the understanding of DGA contributes to the development of DGA interpretation techniques. It will continue to evolve due to a wide variety of industry changes:

- a) New material and new material processing
- b) New transformer designs
- c) New applications of transformers
- d) Changes in data availability and quality
- e) Changes in the operation and use of transformer
- f) Change in the expectation of what DGA interpretation should supply to the transformer owners

This guide represents the best interpretation of the data available at the time of redaction, based on the experience of the experts contributing to this document. The industry should strive to continue to upgrade and improve it.

Several opportunities for improvement have been identified during the revision work that resulted in the present guide. While some effort was put into pursuing these topics, resolution of them remains too elusive to be included in this current guide. A list of these topics is provided as follows:

- Reduce the number of DGA marked as “Investigate” without losing the capability to detect abnormal situations.
- Obtain a better correlation between DGA results and actual fault detection and identification.
- Adapt DGA interpretation to specific applications, such as windfarm, network, GSU, distribution.
- Build an industry wide database of DGA, including all pertinent transformer information, to support the future evolution of this guide.
- Adapt application of DGA interpretation to the use of online DGA monitors, specifically regarding the rate of change calculations.

Annex B

(informative)

DGA data—Evaluating the rate of gas level change

The purpose of this annex is to present general observations on the influence of DGA limitations on rate evaluation with a tutorial application example of the procedure described in 6.1.1.

Trending DGA data can provide insight into changing equipment conditions. Trending can also be helpful to determine the effects of load and other conditions on possible active faults. In these situations, the establishment of a baseline and adequate sampling frequency to observe the variations in the rates of change are necessary. Large changes in the gas generation rate verified through a DGA confirmation sample should place the transformer into a diagnostic observation classification.

Care should be taken when applying rate diagnostics due to possible varying conditions between and among historic sample results. Factors like the insulating liquid temperature at the time of sampling, differing DGA methods between laboratories, and sample quality can make rates of change determinations impossible for one or more of the historic sample data sets. A basic understanding of the DGA method used is necessary so that data from incompatible sources do not generate an alarm condition (e.g., trying to compare on-line DGA results with laboratory based results). This can also apply to results received from different laboratories, e.g., results obtained from methods ASTM D3612A and ASTM D3612C, although it does not prevent a general comparison of the gas profile qualitative analysis.

The length of time between samples can make the rate of change calculation irrelevant as the diagnostic method. An example would be samples taken one day apart and theoretically containing the maximum amount of laboratory equipment error giving a false indication of a large change in the gas generation rate. A closely spaced confirmation sample is normally meant to verify a change in the gas concentrations allowing us to draw conclusions on the equipment condition. There is also the prospect of a gas generation event like a lightning strike compared to an active gassing source that consistently generates a specific amount of gas every day.

Another cautionary item is relevant equipment changes between samples. After maintenance operations that allow intentional or unintentional degassing, like a bushing replacement or insulating liquid processing, have been performed, the establishment of a new DGA baseline should be done. Processing may degas the insulating liquid, but a certain quantity of gas will normally remain in the cellulose insulation material. This residual combustible gas will influence future samples and should not be mistaken for real gas generation. The sample quality also has a direct impact on the ability to trend the results (see 5.1 and 5.2).

B.1 Impact of DGA limitations on the selection and use of rate norms

As a first approach, obtaining the appropriate percentiles rate values to detect DGA anomalies is simply a matter of performing the same statistic computations as for gas levels (see 5.4), but with the analysis applied to the difference between consecutive samples. As rate is generally defined as $\mu\text{L/L/year}$ (ppm/year), it could be possible to perform a simple rate computation by taking the difference between gas levels of two consecutive DGA results and dividing it by the number of days between them, times 365, to obtain $\mu\text{L/L/year}$ (ppm/year), and then obtain the 90th or 95th percentile of the rates population computed in this manner.

However, there is a serious issue with this approach: the 90th and 95th percentile values of rates computed with a certain time interval group (e.g., yearly DGA) are not the same for a different interval group (e.g., quarterly DGA). The difference is quite large and grows exponentially as a function of the inverse of time difference between DGA results (the shorter the interval, the higher the 90th and 95th percentile

values). In other words, it is impossible to obtain a percentile value in this manner that could be applicable to all pairs of samples, independently of the time between them. The normalization to a common time interval (year) simply does not work.

The reason for this counter intuitive result lies in DGA imperfections. Variations between DGA results are known to happen. Part of those variations could be explained by changes in a transformer's condition, such as load or temperature. However, the DGA process itself is also a source of variations. Those variations have several causes, explanation of which is beyond the scope of this guide. Consequently, it should not be expected that two strictly identical samples will produce exactly the same DGA results, even when there is no issue with sampling or DGA process.

In terms of the analysis process, these normal variations are called “reproducibility” and “repeatability.”

Reproducibility is the difference observed for the same sample between different laboratories, or different operators, or different analytical equipment, or at different times. This applies to typical DGA.

Repeatability is the difference observed between repeated analyses of the same sample, by the same operator in a single laboratory, on the same analytical equipment in a short period of time (repeatability is sometimes called “Precision”).

Note that those two values are NOT related to “accuracy,” which is the difference between a result and the “true” value (also called “bias” when applied to a method).

Most of the time (when there is no active gas generation in the transformer), those variations are larger than what is actually taking place in the transformer. Those variations are simply unrelated to the operation of the transformer itself and could generate simple rate computation results that have nothing to do with the condition of the transformer. Worse, the rates computed from these random variations will be also strongly dependent of the time separating the samples.

For example, assume there are two consecutive samples for a transformer that differ by 2 $\mu\text{L/L}$ (2 ppm) due to the intrinsic variability of the DGA results (not the transformer gas levels). Computing a simple yearly rate from these two results will give a value of 2 $\mu\text{L/L/year}$ (2 ppm/year) if the two samples are a year apart. However, if the two samples are a month apart, then the computed value will be 24 $\mu\text{L/L/year}$ (24 ppm/year). If the two samples are a day apart, then the computed rate will be 730 $\mu\text{L/L/year}$ (730 ppm/year). Clearly this would result in radically different diagnostic if applied without discernment.

On the other hand, data analysis has clearly shown that the typical differences between two consecutive samples (deltas) are mostly unrelated to the time between the samples. They are about the same for samples taken a week or a month apart as for samples taken a year or two apart. For a simple rate computation, the difference of time between samples generate vastly different rate values with the same DGA variations, which make percentile values of simple rates unusable.

One way to reduce the impact of these intrinsic DGA process variations on the rate determination is to use more than two samples in the computation. As the variations caused by the DGA process are random, they will tend to cancel each other.

To overcome those limitations of the DGA process, two tables have been developed for this guide to evaluate gas levels increase:

- Table 3: 95th percentile of delta between two consecutive laboratory DGA without any time normalization (Absolute Delta).

Table 3 indicates when the difference between two DGA exceeds the typical variations expected from the DGA process. This could indicate either some active gassing or it could simply be a statistical anomaly that could be ruled out by a follow-up sample.

- Table 4: 95th percentile of rates (slopes) obtained from 3 to 6 consecutive laboratory DGA over a period of 4 to 24 months (rates) normalized in $\mu\text{l/l/year}$ (ppm/year).

Table 4 indicates when the rates of gas evolution exceed the typical rates of gas level in the general population of transformer (i.e., with gas levels below Table 1) and might indicate an active gassing situation.

A general rule is that any results that do not “fit the pattern” should be confirmed by a new sample, unless an obviously critical situation is observed. In such (rare) cases, precautionary actions, during the time a confirmation analysis is performed, might be advisable.

B.2 Example 1

Please note that the data below is only a tutorial example to illustrate the procedure of Figure 2 and 6.1.1. Each transformer being unique, a real-life situation would be different. This example is typical of most transformers.

Table B.1—Multi-points rate tutorial example 1

Point number	Days	μL/L	Delta μL/L	Table 3 norms	μL/L/year	Period in days	Table 4 norms
1	0	5	N/A	N/A	N/A	0	N/A
2	14	9	4	20	N/A	14	N/A
3	27	7	-2	20	N/A	27	N/A
4	40	8	1	20	N/A	40	N/A
5	96	9	1	20	N/A	96	N/A
6	150	7	-2	20	2.1	150	10
7	275	5	-2	20	-4.3	261	10
8	399	6	1	20	-2.4	372	7
9	524	5	-1	20	-2.6	484	7
10	651	38	33	20	13.4	555	7
11	672	6	1	20	-1.6	576	7
12	771	7	1	20	0.1	621	7
13	782	9	2	20	2.0	507	7
14	910	11	2	20	3.6	511	7
15	1042	8	-3	20	3.1	518	7
16	1162	9	1	20	1.7	490	7
17	1282	8	-1	20	-0.1	511	7
18	1402	10	2	20	-0.2	620	7

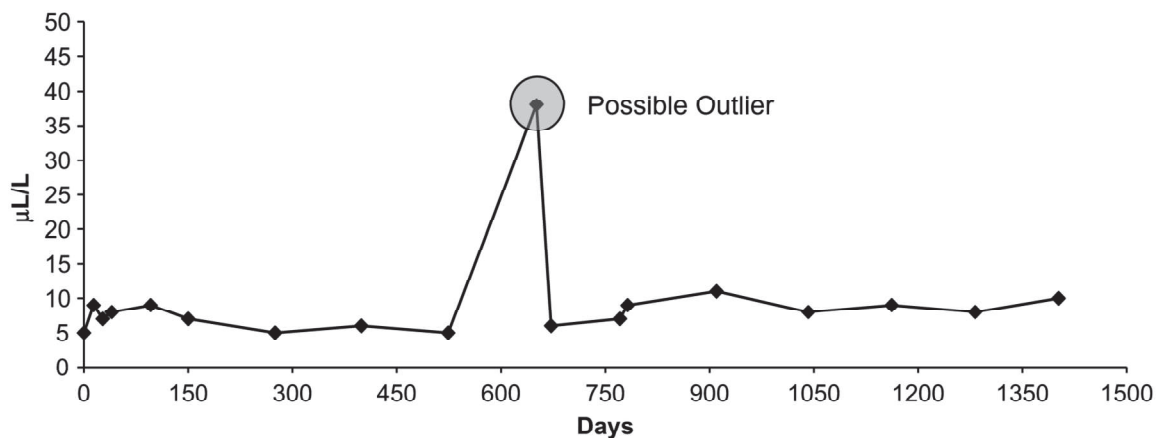


Figure B.1—Multi-points rate example 1

Table B.1 data (plotted in Figure B.1) is an illustrative example (not from a real case) of a series of DGA data points that could be evaluated to determine if an active fault is possibly present in a transformer. In that example, 18 DGA reports are provided from a two years old transformer recently placed under elevated load with an initial period of frequent sampling followed by regular sampling every three months. The discussion is limited to a single gas (C₂H₄) for clarity, but the same process should be applied to all the other gases. Figure B.1 is a graph of data that helps to visualize gas evolution over time.

Table B.1 column headers are explained as:

- Point number: sample number from the start of the periodic screening program
- Days: number of days from the first sample of the regular periodic screening program
- $\mu\text{L/L}$: DGA result in $\mu\text{L/L}$ (ppm)
- Delta $\mu\text{L/L}$: delta from the previous point in $\mu\text{L/L}$ (ppm)
- Table 3 norm: the applicable norm for delta (Table 3)
- $\mu\text{L/L/year}$: computed rate (linear best fit of the last three to six valid points for all periods greater than four months and less than two years)
- Period in days: the sampling period for the rate computations (number of days between the first and the last points of the series used in the linear best fit)
- Table 4 norm: the corresponding norm from Table 4

The transformer, in this example, is a two year old unit with an O_2/N_2 ratio < 0.2 . For this unit, the Table 1 norm is 20 $\mu\text{L/L}$ (ppm), the Table 2 norm is 100 $\mu\text{L/L}$ (ppm), the Table 3 norm is 20 $\mu\text{L/L}$ (ppm), and the Table 4 norms are between 7 to 10 $\mu\text{L/L/year}$ (ppm/year).

Sample 1 is below the norm of Table 1, therefore the DGA is Status 1. Table 3 does not apply as there is no prior sample.

Sample 2 through Sample 5 are below the norm of Table 1 and their computed delta are below Table 3 norm. Rates are not available due to the period between first and most recent point being less than four months, so as per step 4a of 6.1.1, DGA is Status 1.

Starting at Sample 6, the rate could be computed as the minimal period for rate computation (four months) has been met. The last six samples are included in the rate computation.

Sample 6 through Sample 9 are below Table 1 norm, with the delta below the Table 3 norm. The rate is below Table 4 norm, so as per step 4a of 6.1.1, DGA is Status 1.

With Sample 10, although the gas level value is below Table 1, the delta between Sample 9 and Sample 10 exceed Table 3 norm and the computed rate of point 5 to point 10 exceed Table 4 norm. DGA is, therefore, in Status 3.

This could either be the first indication of gassing or it could be the result of a bad sample. An emergency confirmation sample is requested, as per step 4b of 6.1.1.

Sample 11 is the result of the confirmation sample. As per step 4c, the delta is computed between Sample 9 and Sample 11. The resulting delta of 1 $\mu\text{L/L}$ is well below the Table 3 norm, indicating that Sample 10 is a bad sample. Rate is recomputed with point 5 to point 11, omitting point 10, and gives a result of $-1.6 \mu\text{L/L/year}$ and confirms that Sample 10 was bad. As per step 4d, DGA is Status 1. Point 10 is removed from all future rate computations.

The Sample 12 through Sample 18 values are all below Table 1, all deltas are below Table 3, and all rates are below Table 4 (point 10 not used for rate computation) for a DGA Status 1, confirming Sample 10 was indeed a bad sample.

Regular screening DGA test protocol is maintained.

B.3 Example 2

Please note that the data below is only a tutorial example to illustrate the procedure of Figure 2 and 6.1.1. Each transformer being unique, a real-life situation would be different. It should be noted that this tutorial example is more complex than most usual cases encountered in normal operation. This is done purposely to illustrate some of the steps of 6.1.1.

Table B.2—Multi-points rate tutorial example 2

Point number	Days	μL/L	Delta μL/L	Table 3 norms	μL/L/year	Period in days	Table 4 norms
1	0	5	N/A	N/A	N/A	0	N/A
2	17	9	4	20	N/A	17	N/A
3	68	11	2	20	N/A	68	N/A
4	80	14	3	20	N/A	80	N/A
5	122	34	20	20	75	122	7
6	150	30	-4	20	69	150	7
7	157	30	0	20	68	140	7
8	179	39	9	20	85	111	7
9	204	32	-7	20	53	124	7
10	303	33	1	20	1.3	181	7
11	359	38	5	20	8.2	209	7
12	384	66	28	20	33	227	7
13	410	31	-35	20	0.2	253	7
14	561	27	-4	20	-8.0	382	5
15	649	48	21	20	6.9	445	5
16	736	41	-7	20	7.8	433	5
17	751	61	20	20	17	392	5
18	816	58	-3	20	28	406	5

Table B.2 data (plotted in Figure B.2) is an illustrative example (not from a real case) of a series of DGA data points that could be evaluated to determine if an active fault is possibly present in a transformer. In that example, 18 DGA reports are provided from a transformer returned to service after repair and under close surveillance (frequent DGA results). (The discussion is limited to a single gas (C₂H₄) for clarity, but the same process should be applied to all the other gases.) See description of Table B.1 in B.2 for the column header description.

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IEEE Guide for the Interpretation of Gases Generated in Mineral Oil-Immersed Transformers

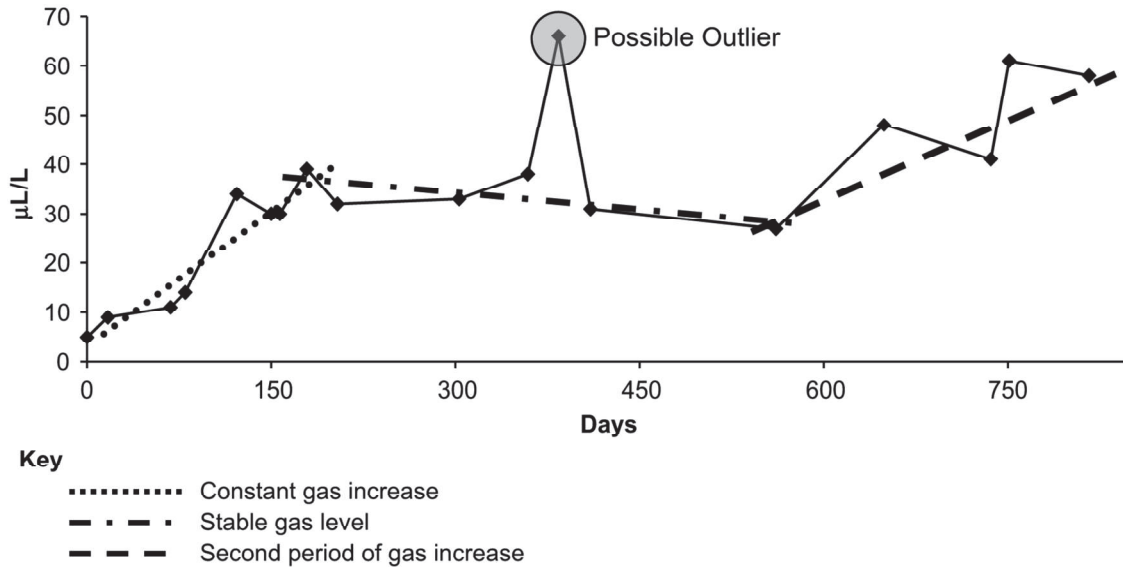


Figure B.2—Multi-points rate example 2

Plotting Table B.2 data in function of time (Figure B.2) reveals the following:

- One group of data (point 1 through point 8) indicating a constant gas increase (small dashes line)
- A second group of data indicating a stable gas level (point 8 through point 14) (dashes-dots line)
- A possible outlier (point 12) (shaded circle)
- A third group of data indicating a second period of gas increase (point 14 through point 18) (large dashes line)

Those different periods, and the outlier, are easy to see when all the points are available and placed in a graph, such as Figure B.2.

However, in practice, an operator will have access to only one new point at the time and would have to make an evaluation in “real time” with the new data, without the benefit of knowing what the evolution will be.

Computing a simple gas generation rate by subtracting the previous value from the last and dividing by the period between the samples seems to be an obvious way to analyze new points. However, as discussed in B.1, this could be misleading due to the inherent variability of the DGA process. It is preferable to apply a multi-point linear best fit (available in most spreadsheets) over a significant period of time for rate computation to reduce the impact of these normal DGA variations.

This tutorial example is for C₂H₄ data from an eleven-year-old unit with an O₂/N₂ ratio above 0.2. The Table 1 C₂H₄ level norm is 60µL/L (ppm), Table 2 is 125 µL/L (ppm), Table 3 Delta norm is 20 µL/L (ppm), and Table 4 is between 7 µL/L/year (ppm/yr) (4 to 9 mo) and 5 µL/L/year (ppm/year) (9 to 24 mo) for the period covered in this example.

If the procedure outlined in Figure 2 and described in 6.1.1 is applied, the following interpretation is obtained:

Point 1 through point 4 are in DGA status 1 for both levels (Table 1) and delta µL/L (delta ppm) (Table 3).

With point 5, the procedure of Figure 2 indicates that the maximum allowable delta (Table 3) is reached, [20 µL/L (ppm)] indicating possible gassing activities. The DGA status could become 2 if a new sample confirms the change. Point 1 through point 5 are used to compute a linear best fit, as the period between

point 1 and 5 exceeds 4 mo. It can be observed that the rate is 75 $\mu\text{L/L/year}$ (ppm/year), which is above the Table 4 norm, indicating probable gassing activity and placing the DGA in status 3.

Gassing activity is monitored for confirmation with point 6 through point 8. Point 1 through point 6 confirms a rate above Table 4 [69 $\mu\text{L/L/year}$ (ppm/year)], and the DGA as status 3. The point 8 delta is below the norm of Table 3. However, the rate computed from point 2 through point 8 (6 most recent points) is 85 $\mu\text{L/L/year}$ (ppm/year), which is above the Table 4 norm, confirming a constant gassing activity and a DGA status 3.

A transformer assessment is performed at that point, with the assistance of a DGA expert, to evaluate what action should be taken. Adjustment to the transformer operating condition is performed.

Point 9 through point 11 seem to indicate a reduction of the gassing activity. The rate computed with point 5 through point 10 gave a value of 1.3 $\mu\text{L/L/year}$ (ppm/year), which is essentially flat and below Table 4. Since gas level is also below the Table 1 norm, the DGA is back in status 1.

However, point 12 indicates a sudden jump, even with the new operating conditions, exceeding the value of Table 3. The rate computed on the last 6 points (point 7 through point 12) is 33 $\mu\text{L/L/year}$ (ppm/year). This could either be a sample error or an indication of a deterioration of the existing condition due to new gassing activity. A priority confirmation sample is taken along with implementing extra precautions in the transformer operation while awaiting the confirmation sample results. The new sample (13) does not confirm the sudden increase; indicating that point 12 is probably an error. After review, the decision is taken to not make any new adjustment, but to maintain the restrictions implemented after point 8 and to continue close surveillance. Point 12 is considered an outlier and is removed from subsequent rate computations (shaded cell of Table B.2).

Point 14 confirms the apparent lack of activity [the rate for point 8 to point 14 (last six valid points) is $-8.0 \mu\text{L/L/year}$ (ppm/year), excluding the outlier] but then point 15 exceeds the maximum delta of Table 3, so close surveillance is maintained and DGA is now status 2. Rate computed from point 10 to point 16 seem to indicate new gassing activity with a rate above Table 4 norm, with the point 17 value just above Table 2 norm and the delta from point 16 to point 17 equal to the Table 3 norm. The linear best fit computed rate for point 11 to point 17 is 17 $\mu\text{L/L/year}$ (ppm/year), which is less than the first segment, but nevertheless still above Table 4, indicating that a gassing condition is still active, placing the DGA in status 3 again. Point 18 confirms the gassing with a rate of 28 $\mu\text{L/L/year}$ (ppm/year) for point 13 to point 18.

This is a tutorial example only. Each individual case will be different.

B.4 Example 3

This example illustrates a case of a transformer that experienced a sudden and large or extreme increase after a long period of gassing inactivity. This case is typical of most gassing events. It is an extreme situation that is obvious and does not require any finesse or norms to interpret, once confirmation samples have been obtained.

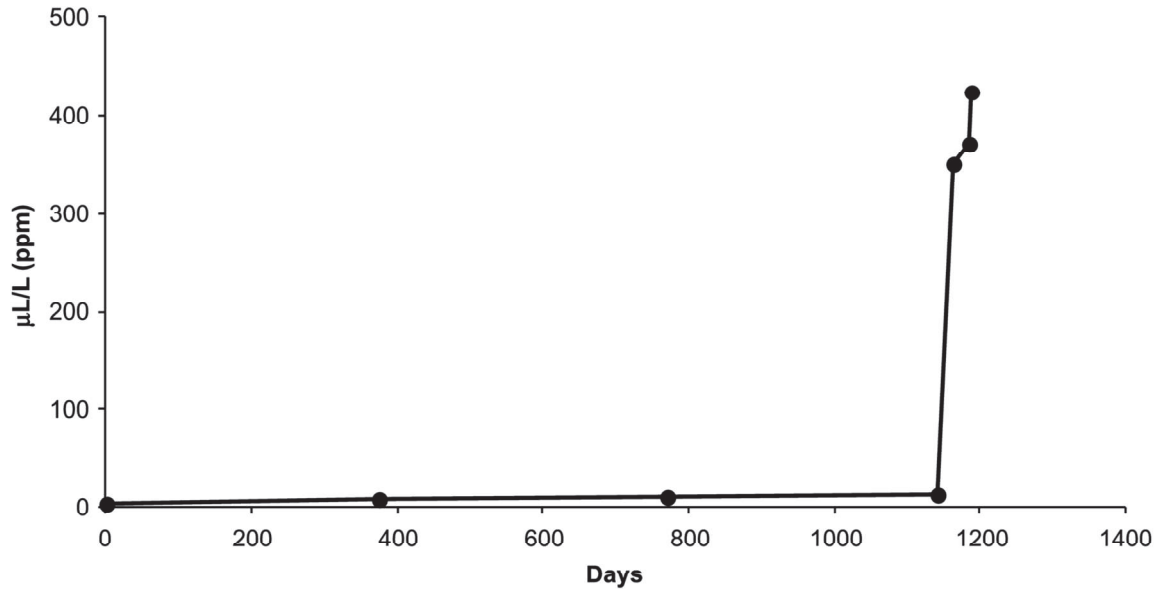


Figure B.3—Example of an extreme DGA evolution

B.5 General application

It should be remembered that each situation is unique, and no process can be totally universal. Therefore, a new set of data would be different than the examples presented here (see Annex E for real life examples). However, the procedure should follow the general lines of 6.1.2, but could be adapted depending of the situation. When data indicate a possible transformer anomaly, consultation with the transformer manufacturer, the transformer specialist, the owner and the operator should be undertaken.

It is generally recognized among transformer experts that actual gas levels are less significant than active gassing. A high level of gas could be the result of a previous event, no longer active, or a slow accumulation over a long period that presents no immediate issue (especially for CO and CO₂). On the other hand, a sign of ongoing gassing, even when levels are still low, is an indication of some phenomena occurring in the transformer and should always warrant extra investigation.

Annex C

(informative)

Typical faults

The purpose of this annex is to identify and classify the typical faults one might encounter when operating a power transformer, and to also discuss these fault types in brief detail.

C.1 The six basic types of faults

The six basic types of faults indicated below and abbreviated in Table C.1 can be identified by DGA results, using methods described in 6.2 and Annex D.3.

- Partial discharges (PD) of the cold plasma (corona) type, resulting in possible X-wax deposition on paper insulation.
- Discharges of low energy (D1), in mineral oil and/or paper, evidenced by larger carbonized perforations through paper (punctures), carbonization of the paper surface (tracking), carbon particles in mineral oil (as in tap changer diverter operation), or partial discharges of the sparking type, inducing pinhole or carbonized perforations (punctures) in paper.
- Discharges of high energy (D2), in mineral oil and/or paper, with power follow-through, evidenced by extensive destruction and carbonization of paper, metal fusion at the discharge extremities, extensive carbonization in mineral oil and, in some cases, tripping of the equipment, confirming the large current follow-through.
- Thermal faults, in mineral oil and/or paper, below 300 °C if the paper has turned brownish (T1), and above 300 °C if it has carbonized (T2).
- Thermal faults of temperatures above 700 °C (T3) if there is strong evidence of carbonization of the mineral oil, metal discoloration (800 °C) or metal fusion (>1000 °C).

Table C.1—Abbreviations of basic faults

PD	Partial discharges of corona type
D1	Discharges of low energy or partial discharges of sparking type
D2	Discharges of high energy
T1	Thermal fault, $t < 300$ °C
T2	Thermal fault, 300 °C $< t < 700$ °C
T3	Thermal fault, $t > 700$ °C

C.2 Additional sub-types of faults

The additional sub-types of faults indicated in Table C.2 can be identified using methods described in D.3 to D.5.

- Stray gassing of mineral oil (S) at temperatures < 200 °C (in mineral oil only), because of the chemical instability of mineral oils produced by some modern refining techniques. It could also occur due to incompatibility between materials (e.g., such as some metal pasivators).
- Overheating (O) of paper or mineral oil < 250 °C (therefore without carbonization of paper and loss of its electrical insulating properties).

- Possible carbonization of paper (C).
- Thermal faults T3 in mineral oil only (no paper involved) (T3-H) .
- Catalytic reactions (R) between water and galvanized steel in oil sampling valves of transformers or with tank steel (rust) (R faults are very rare).

These fault subtypes have been described in detail in the IEEE PES Transformers Committee Tutorial “Interpretation of Dissolved Gas Analysis in Electrical Equipment with Duval Triangles and Pentagons” [B92] and in “The Duval Pentagon—A new complementary tool for the interpretation of DGA in transformers,” [B90] and supported by several inspected cases.

Table C.2—Abbreviations of fault subtypes

S	Stray gassing at temperatures < 200 °C,
O	Overheating < 250 °C without carbonization of paper
C	Possible paper carbonization
T3-H	Thermal fault T3 in mineral oil only
R	Catalytic reaction

Annex D

(informative)

Fault identification methods

The purpose of this Annex is to present fault identification methods. These methods include various data ranges, classifications, tables, ratio analysis, and use of visual aids such as Duval’s Triangle and Pentagon.

D.1 Key Gas method

The Key Gas method is summarized in Table D.1:

Table D.1—Key Gas method

Key Gas	Fault type	Typical proportions of generated combustible gases
Ethylene (C ₂ H ₄)	Thermal mineral oil	Predominantly Ethylene with smaller proportions of Ethane, Methane, and Hydrogen. Traces of Acetylene at very high fault temperatures.
Carbon-Monoxide (CO)	Thermal mineral oil and cellulose	Predominantly Carbon Monoxide with much smaller quantities of Hydrocarbon Gases Predominantly Ethylene with smaller proportions of Ethane, Methane, and Hydrogen
Hydrogen (H ₂)	Electrical low energy partial discharge (PD)	Predominantly Hydrogen with small quantities of Methane and traces of Ethylene and Ethane.
Hydrogen and Acetylene (H ₂ , C ₂ H ₂)	Electrical high energy (arcing)	Predominantly Hydrogen and Acetylene with minor traces of Methane, Ethylene and Ethane. Also, Carbon Monoxide if cellulose is involved.

When the main gas formed in DGA results is one of the four key gases in column 1, together with the secondary gases in column 3, the type of fault is provided in column 2.

The limitation of the Key Gas method is that it results in many inconclusive or wrong fault identifications (typically 50%) when applied automatically with software. This is because often it is not clear which is the main gas formed, also because the main gas formed may not be one of those used in the Key Gas method. Furthermore, CO is not always a good indicator of a fault in paper (see D.8).

When applied manually by experienced DGA users, the number of wrong fault identifications with the Key Gas method is lower (typically 30%) but still high.

D.2 Doernenburg Ratios method

The Doernenburg Ratios method is illustrated in Table D.2:

Table D.2—Doernenburg Ratios method

Suggested fault diagnosis	Ratio 1 (R1) CH ₄ /H ₂ Extracted from mineral oil gas space		Ratio 2 (R2) C ₂ H ₂ / C ₂ H ₄ Extracted from mineral oil gas space		Ratio 3 (R3) C ₂ H ₂ / CH ₄ Extracted from mineral oil gas space		Ratio 4 (R4) C ₂ H ₆ / C ₂ H ₂ Extracted from mineral oil gas space	
	1 – Thermal decomposition	> 1.0	> 0.1	< 0.75	< 1.0	< 0.3	< 0.1	> 0.4
2 – Corona (low intensity PD)	< 0.1	< 0.01	Not significant		< 0.3	< 0.1	> 0.4	> 0.2
3 – Arcing (high intensity PD)	> 0.1 < 1.0	> 0.01 < 0.1	> 0.75	> 1.0	> 0.3	> 0.1	< 0.4	< 0.2

It is a historic method less used today. It has the same limitation as the Rogers Ratios method. See G.4 for more information.

D.3 Duval Pentagon 1 method

The Duval Pentagon 1 method is illustrated in Figure D.1.

The Duval Pentagon 1 uses all five hydrocarbon gases (H₂, C₂H₆, CH₄, C₂H₄ and C₂H₂). The order of gases at the five summits of Pentagons 1 and 2 correspond to the increasing energy or temperature of the faults producing these gases (from H₂ to C₂H₂).

The six basic types of faults of (PD, D1, D2, T1, T2 and T3) indicated in Annex C.1 can be detected with Duval Pentagon 1, as in the case of Duval Triangle 1 (see 6.2.3), as well as stray gassing of mineral oil (S) indicated in Annex C.2.

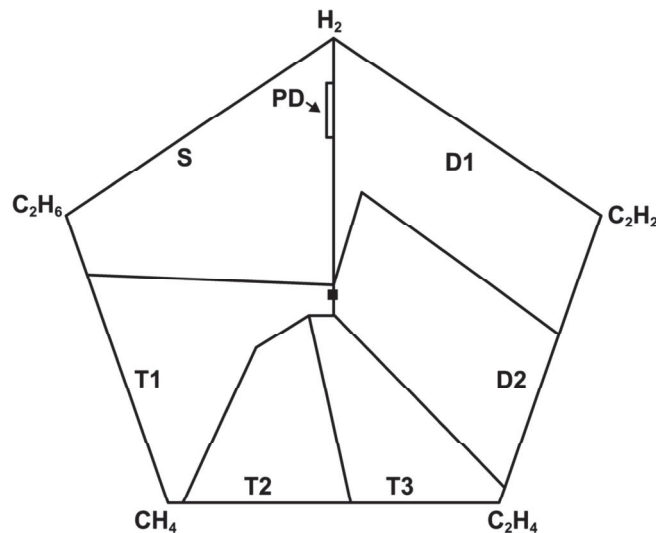


Figure D.1—Duval Pentagon 1 method

The procedure for calculating and displaying DGA points in Duval Pentagon 1 are described in “The Duval Pentagon—A new complementary tool for the interpretation of dissolved gas analysis in transformers,” [B90].

The numerical values of the (x, y) coordinates of zone boundaries in Pentagon 1 are indicated below [the dot of Figure D.1 is at coordinates (0,0) and the apex H2 is at coordinates (0, 40)]¹¹:

- PD: (0, 33), (-1, 33), (-1, 24.5), (0, 24.5);
- D1: (0, 40), (38, 12), (32, -6.1), (4, 16), (0, 1.5);
- D2: (4, 16), (32, -6.1), (24.3, -30), (0, -3), (0, 1.5);
- T3: (0, -3), (24.3, -30), (23.5, -32.4), (1, -32); (-6, -4);
- T2: (-6, -4), (1, -32.4), (-22.5, -32.4);
- T1: (-6, -4), (-22.5, -32.4), (-23.5, -32.4), (-35, 3), (0, 1.5); (0, -3);
- S: (0, 1.5), (-35, 3.1), (-38, 12.4), (0, 40), (0, 33), (-1, 33), (-1, 24.5), (0, 24.5);

D.4 Duval Triangles 1, 4 and 5 methods

The Duval Triangle 1 method is described in 6.2.3. The general methodology as Triangle 1 is applied to obtain interpretations with Triangle 4 and Triangle 5 and is as follows:

In a DGA report, if $(C_2H_2) = x$; $(C_2H_4) = y$; $(CH_4) = z$, in $\mu\text{L/L}$ (ppm), first calculate the sum $(x + y + z)$, then the relative % of each gas $\%C_2H_2 = 100x / (x + y + z)$; $\%C_2H_4 = 100y / (x + y + z)$; $\%CH_4 = 100z / (x + y + z)$.

These relative % values are the coordinates of the DGA point in Duval Triangle 1. As illustrated, for example, in Figure D.2 where $x = 25 \mu\text{L/L}$ (ppm) of CH_4 , $y = 15 \mu\text{L/L}$ (ppm) of C_2H_4 and $z = 10 \mu\text{L/L}$ (ppm) of C_2H_2 .

Relative % values are $CH_4 = 50\%$, $C_2H_4 = 30\%$ and $C_2H_2 = 20\%$; in zone D2.

¹¹ Free algorithms for using the Duval Pentagons methods are available in the IEEE Std C57.104-2019 directory located at: https://standards.ieee.org/content/dam/ieee-standards/standards/web/download/C57.104-2019_downloads.zip.

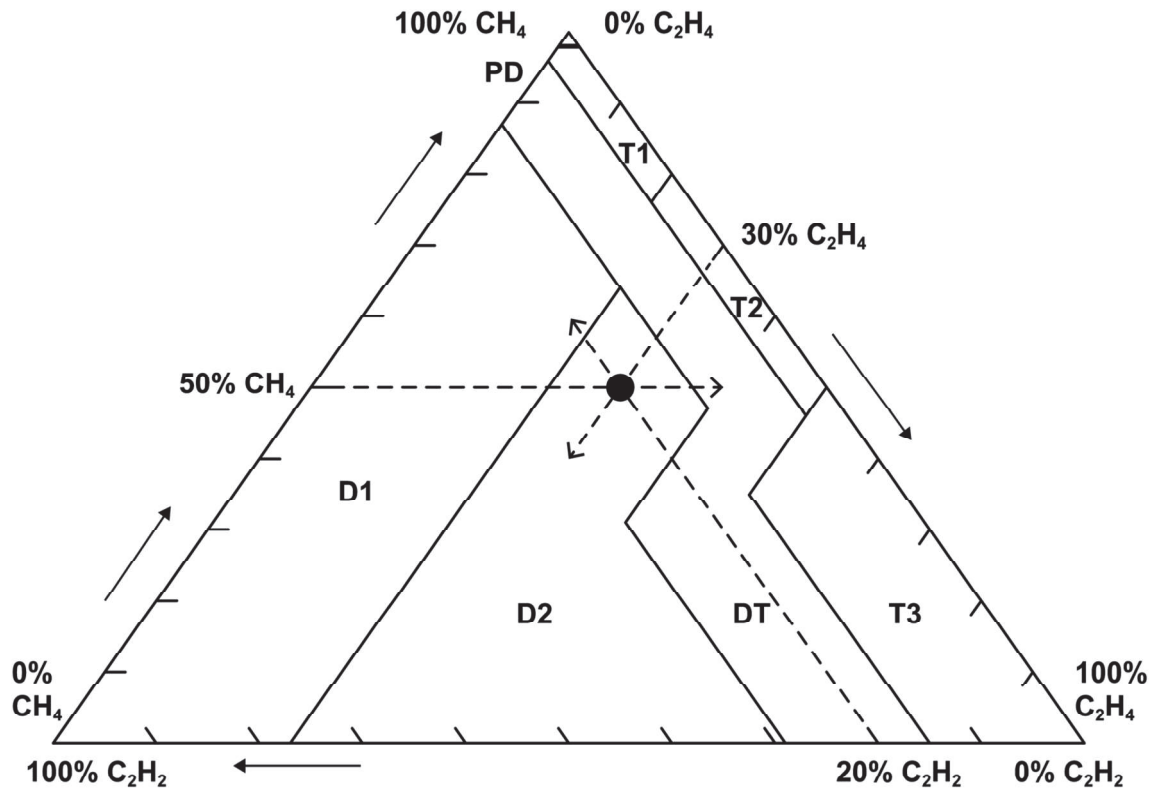


Figure D.2—Example of Duval Triangle 1 representation

Duval Triangles 4 and 5 are built and used in the same manner but use different gases and zones. Duval Triangle 4 uses H_2 , CH_4 and C_2H_6 and Duval Triangle 5 uses CH_4 , C_2H_4 and C_2H_6 .

Duval Triangles 4 and 5 can be utilized to obtain more information about sub-types of thermal faults described in C.2. See also 6.2.3.

When low energy or low temperature faults are identified using the Duval Triangle 1 (PD, T1 or T2), more information can be obtained with Duval Triangle 4.

When high, or very high, temperature faults have been identified with Duval Triangle 1 (T2 or T3), more information can be obtained using the Duval Triangle 5.

The Duval Triangle 4 method is illustrated in Figure D.3.

The Triangle 4 method allows for distinguishing between faults S, O, PD, R (see C.2), which are of relatively minor concern in transformers, and potentially more dangerous faults C, which involve possible carbonization of paper. Faults R will appear at the very top of Triangle 4 (H_2 only).

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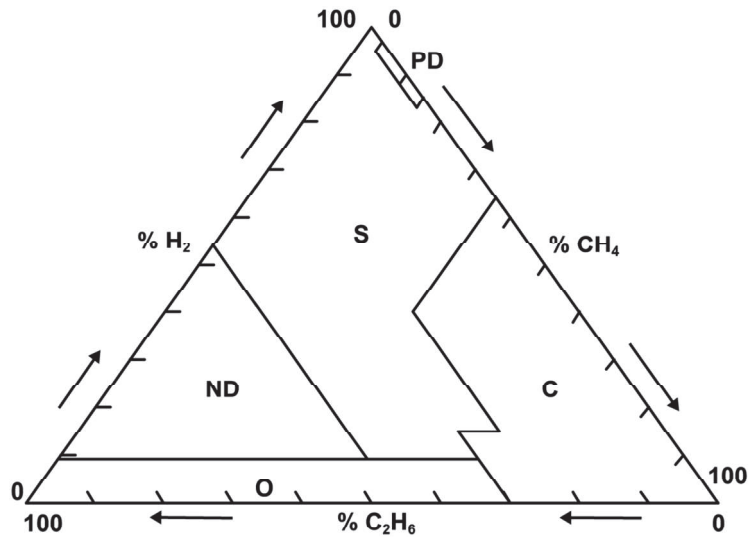


Figure D.3—Duval Triangle 4 method for low temperature faults

Numerical values for fault zone boundaries of Duval Triangle 4 method are the following, expressed in %H₂, %CH₄ and %C₂H₆:

Table D.3—Fault zone boundaries for Figure D.3

Gas% / Fault	% H ₂	% CH ₄	% C ₂ H ₆
PD	—	≥ 2 and < 15	< 1
S	≥ 9	—	≥ 30 and < 46
	≥ 15	—	≥ 24 and < 30
	—	< 36	≥ 1 and < 24
	—	< 36 and ≥ 15	< 1
	—	< 2	< 1
O	< 9	—	≥ 30
C	—	≥ 36	≥ 24
	< 15	—	≥ 24 and < 30
ND	≥ 9	—	≥ 46

The Duval Triangle 5 method is illustrated in Figure D.4:

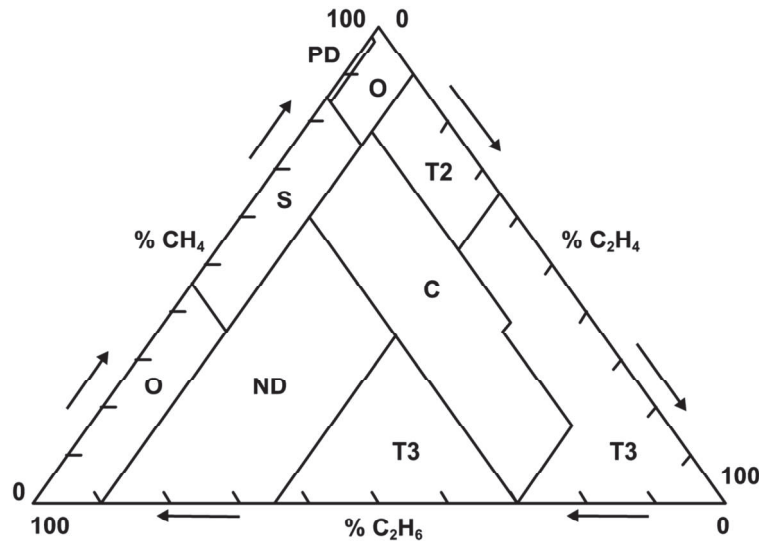


Figure D.4—Duval Triangle 5 method for high temperature fault

The Triangle 5 method allows a user to distinguish between high temperature faults T3/T2 in mineral oil only, of lesser concern in transformers, and potentially more dangerous faults C involving possible carbonization of paper.

Numerical values for fault zone boundaries of Duval Triangle 5 method are the following, expressed in %CH₄, %C₂H₄ and %C₂H₆:

Table D.4—Fault zone boundaries for Figure D.4

Gas% / Fault	% CH ₄	% C ₂ H ₄	% C ₂ H ₆
PD	—	< 1	≥ 2 and < 14
O	—	≥ 1 and < 10	≥ 2 and < 14
	—	< 1	< 2
S	—	< 10	≥ 54
	—	< 10	≥ 14 and < 54
T2	—	≥ 10 and < 35	< 12
T3	—	≥ 35	< 12
	—	≥ 50	≥ 12 and < 14
	—	≥ 70	≥ 14
	—	≥ 35	≥ 30
C	—	≥ 10 and < 50	≥ 12 and < 14
	—	≥ 10 and < 70	≥ 14 and < 30
ND	—	≥ 10 and < 35	≥ 30

Note that:

- Triangles 4 and 5 should never be used for faults identified first with Triangle 1 as electrical faults D1 or D2.
- Triangle 4 should be used only in case of faults identified first as faults PD, T1 or T2 in Triangle 1.
- Triangle 5 should be used only in case of faults identified first as faults T2 or T3 in Triangle 1.

- d) DGA points occurring in zones C indicate a possibility of carbonization of paper, not a 100% certainty, and further investigations with carbon oxides and furans should be undertaken.

The procedure for calculating and displaying DGA points in Duval Triangles 4 and 5 is the same as for Triangle 1 in 6.2.3.¹²

Numerical values of zone boundaries are indicated in Table D.3/Figure D.3 and Table D.4/Figure D.4.

D.5 Duval Pentagon 2 method

If thermal faults (T1, T2, and T3) have been identified with Duval Pentagon 1, more information can be obtained on these faults with Duval Pentagon 2, as in the case of Duval Triangles 4 and 5.

The Duval Pentagon 2 method is illustrated in Figure D.5.

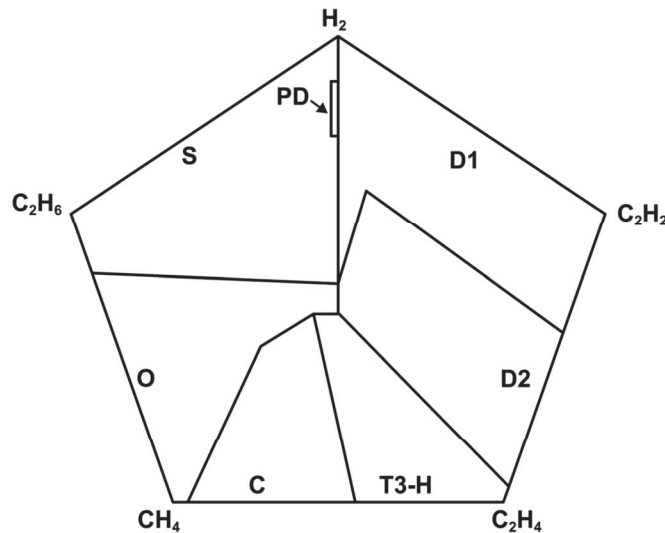


Figure D.5—Duval Pentagon 2 method

The Pentagon 2 method allows for detection of the 3 basic types of electrical faults (PD, D1 and D2) as in Duval Pentagon 1, and to further distinguish between the 4 additional sub-types of thermal faults of D.2 (S, O, C and T3 in mineral oil only).

In Duval Pentagon 2, faults T3 in mineral oil only are indicated as T3-H, where H is for “Huile” or “oil” in French.

NOTE—DGA points occurring in zone C indicate a possibility of carbonization of paper, not a 100% certainty, and further investigations with carbon oxides and furans should be undertaken.

The procedure for calculating and displaying DGA points in Duval Pentagons is described in “The Duval Pentagon—A new complementary tool for the interpretation of dissolved gas analysis in transformers,” [B90].

¹² Free algorithms for using the Duval Triangles methods are available in the IEEE Std C57.104-2019 directory located at: https://standards.ieee.org/content/dam/ieee-standards/standards/web/download/C57.104-2019_downloads.zip.

The numerical values of the (x, y) coordinates of zone boundaries of Pentagon 2 are indicated below:¹³

- PD: (0, 33), (-1, 33), (-1, 24.5), (0, 24.5);
- D1: (0, 40), (38, 12), (32, -6.1), (4, 16), (0, 1.5);
- D2: (4, 16), (32, -6.1), (24.3, -30), (0, -3), (0, 1.5);
- S: (0, 1.5), (-35, 3.1), (-38, 12.4), (0, 40), (0, 33), (-1, 33), (-1, 24.5), (0, 24.5);
- T3-H: (0, -3), (24.3, -30), (23.5, -32.4), (2.5, -32.4), (-3.5, -3);
- C: (-3.5, -3), (2.5, -32.4), (-21.5, -32.4), (-11, -8);
- O: (-3.5, -3), (-11, -8), (-21.5, -32.4), (-23.5, -32.4), (-35, 3.1), (0, 1.5), (0, -3).

D.6 Mixtures of faults

Duval Triangles 1, 4, 5 and Pentagons 1, 2 methods, as well as all other diagnosis methods (Key Gas, Rogers Ratios, Doernenburg Ratios), were initially developed for detecting single faults only.

However, multiple faults (mixtures of faults) often occur rather than single faults and may be more difficult to identify with certainty. For instance, actual mixtures of faults T3+D1 may sometimes appear in terms of gas formation as faults D2 in Triangle 1, Pentagon 1, and other diagnosis methods (Rogers Ratios, etc.), while actual mixtures of faults T3 in mineral oil (T3-H) and O may appear as faults C in Triangle 5 and Pentagon 2.

Mixtures of faults may be suspected when fault identifications provided by Duval Triangles 1, 4, and 5 and Pentagons 1 and 2 for the same DGA results are different. This is because each graphical representation is more sensitive to some gases and some faults than to others. For example, Triangle 4 and the Pentagons are more sensitive to H₂ and faults S and PD, while Triangle 1 and Triangle 5 are more sensitive to C₂H₄ and faults T3.

If the position of the DGA point changes with time in the Triangles and the Pentagons, this indicates that a new fault has formed over the old one or another source of gas formation (a different type of fault has become active) exists. To get a better identification of this new fault, gas concentrations from the previous DGA results may be subtracted from the most recent ones. The subtracted (delta) values will thus be due only to the new fault. If delta values are negative for some gases, this means that no additional amounts (zero $\mu\text{L/L}$) of these gases have been formed because of the new fault since the previous sample, and that some of those gases previously formed have started to escape from the transformer. When identifying the new fault, negative delta values should, therefore, be replaced by zero $\mu\text{L/L}$. Note the previous discussion of the topics of repeatability and reproducibility, which may also contribute to a negative calculated difference.

The possible presence of multiple faults may be useful information during the inspection of transformers.

D.7 When to use the Duval Pentagons and Triangles

If interest is only in the six basic types of faults in C.1 and by single faults, the display of DGA points would be done using the Pentagon 1 or Triangle 1.

If there is also an interest in the additional sub-types of faults in C.2, Pentagon 2 and Triangles 4 or 5 should be used.

¹³ Free algorithms for using the Duval Pentagons methods are available in the IEEE Std C57.104-2019 directory located at: https://standards.ieee.org/content/dam/ieee-standards/standards/web/download/C57.104-2019_downloads.zip.

When detection of mixtures of faults is desired, the diagnosis provided by the pentagons and the triangles can be compared. If they do not agree, this may be an indication of multiple faults. Use subtracted (Δ) values as indicated in D.6 to further identify these multiple faults.

D.8 Interpretation of CO and CO₂

Until recently, CO and CO₂ were considered as good indicators of paper involvement in faults (see D.1). Recent investigations at CIGRE (see [B72]), and in preparation of IEC 60599 [B103] revision, however, have shown that this is not always the case. The present view on the interpretation of CO and CO₂ is the following.

- a) High concentrations of CO ($> 1000 \mu\text{L/L}$ (ppm)) and/or low CO₂/CO ratios (< 3), WITHOUT the formation of significant amounts of hydrocarbon gases, are NOT an indication of a fault in paper, particularly in closed transformer, but are rather due to mineral oil oxidation under conditions of limited supply of O₂.
- b) High concentrations of CO ($> 1000 \mu\text{L/L}$ (ppm)) and low CO₂/CO ratios (< 3), TOGETHER WITH the formation of significant amounts of hydrocarbon gases, may be an indication of a fault in paper. This should be confirmed, however, by Pentagon 2 and Triangles 4, 5, and other observations (e.g., carbon oxides and furans).
- c) High concentrations of CO₂ ($> 10\,000 \mu\text{L/L}$ (ppm)), high CO₂/CO ratios (> 20) and high values of furans ($> 5 \mu\text{L/L}$ (ppm)) are an indication of the slow degradation of paper at relatively low temperatures ($< 140 \text{ }^\circ\text{C}$), down sometimes to very low degrees of polymerization (DPs) of paper (e.g., 150 to 100). In the very large majority of cases, however, this does not prevent the transformer from operating normally, even in the presence of an external short circuit. However, there are concerns that the low DP paper may not always withstand strong transient over-currents or short circuits. See “Significance and detection of very low degree of polymerization of paper in transformers” [B93].
- d) Concentrations of CO and CO₂ below Table 1 of this guide, corresponds to normal gassing in transformers without faults.
- e) Zero or very low rates of change of CO and CO₂ do not necessarily mean the absence of a fault in paper. Localized faults in small volumes of paper often do not produce detectable amounts of CO and CO₂ compared to the usually high background of these gases in service. However, they often produce significant amounts of the other hydrocarbon gases, allowing the detection of faults in paper with Pentagon 2 and Triangles 4 or 5.

D.9 Other useful gas ratios for fault identification

D.9.1 The O₂/N₂ ratio

Decreasing values of this ratio indicate overheating and oxidation of mineral oil and can be used to confirm thermal faults identified in this annex.

Increasing values may indicate leaks in the air preservation system of transformers (membrane or nitrogen blanket).

D.9.2 The C₂H₂/H₂ ratio

Values of this ratio > 3 may indicate leaks or contamination from the tap-changer compartment into the main tank. If such contamination is suspected, it should be investigated.

Annex E

(informative)

Case studies¹⁴

E.1 Unintentional core ground

Background—Transformers have many components that interact and affect equipment operation. The transformer insulation system is typically comprised of cellulose material (paper insulation) and insulating liquid-like mineral oil. Contamination of the insulating liquid or a loss of insulation material can produce an energy source that generates gases from the insulating liquid or cellulose material. The cellulose material is the paper wrapping around conductors and pressboard used for insulation clearance and spacer material. Component movement can displace the pressboard or tear the paper which can decrease the insulation resistance. This one-year-old power transformer was operating in a substation at 161 kV to 13.8 kV with a base capacity of 30 MVA.

Technical Explanation—Transformers require an iron core to increase electro-magnetic field interactions between the windings. The iron core has one intentional ground point typically bolted at the top of the core or through a connection to a core ground bushing. Other possible iron core contact points to ground are insulated with cellulose or man-made materials. Grounds can develop when these materials become displaced or damaged, which can allow the iron core to come into contact with a ground point. Also, debris buildup can reduce the insulation resistance allowing current flow which creates an energy source like heat. The current flow can vary with the insulation resistance of the unintentional core ground and can reach several hundred amps. This current flow can produce temperatures capable of fusing metal along with combustible gases and carbon. High currents can burn away the intentional core ground connection leaving an unreliable ground connection which will allow a potential to accumulate on the iron core.

Analysis—Following a close proximity short circuit event to the transformer, the transformer in this case study developed a gassing issue. Table E.1 shows DGA history sample results so the combustible gas concentrations are above the $O_2/N_2 \leq 0.2$ in the transformer age in years category of 1 to 10 years. The DGA sample results in Table E.1 are also above the Table 2 concentrations for the same category, and are a case of extreme DGA for CH_4 and C_2H_4 (see 6.1.2.4). The confirmation sample (data point 3) and monitoring sample (data point 4) confirms the active gassing source for a Status 3. The event occurred between data points 1 and 2. Data point 1 combustible gas results are very low and should not be used in the diagnostic models like Duval Triangle.

Table E.1—DGA sample results for unintentional core ground in $\mu\text{L/L}$ (ppm)

Data point	Sample date:	H ₂	CH ₄	C ₂ H ₆	C ₂ H ₄	C ₂ H ₂	CO	CO ₂	N ₂	O ₂
1	4-Feb-03	0	0	0	0	0	23	188	108 233	13 364
2	13-Jan-04	95	421	128	695	7	25	360	76 540	2 304
3	28-Jan-04	104	404	138	678	5	31	343	83 976	4 503
4	10-Feb-04	120	554	199	839	9	30	378	86 795	2 387

The data point 2 sample reports a large increase in combustible gas levels that was verified with a confirmation sample. Data point 4 from February 10, 2004 indicates that the gassing source is active as

¹⁴ Material reprinted with permission from The Hartford Steam Boiler Inspection and Insurance Company, “TOGA® Presentation; Case Study Review” © 2012.

indicated by the ethylene gas concentration delta of 161 $\mu\text{L/L}$ (ppm) reported in Table E.2. Depending on the hydrocarbon gas, an increase in the temperature source will generally affect the gas generation rate. An increasing gas rate of change is normally associated with a deteriorating condition.

Table E.2—DGA delta $\mu\text{L/L}$ (ppm) between successive sample

Data point	Sample dates	H ₂	CH ₄	C ₂ H ₆	C ₂ H ₄	C ₂ H ₂	CO	CO ₂
2	13-Jan-04	95	421	128	695	7	-2	172
3	28-Jan-04	9	-17	10	-17	-2	6	-17
4	10-Feb-04	16	150	61	161	4	-1	35

The Rogers Ratios diagnostic model uses combustible gas results combined in ratios to obtain a diagnosis. The criterion was based on field inspection experience. The original Rogers Ratios model with four ratios reported a core heating issue that is consistent with an unintentional core ground.

The Duval Triangle diagnostic method for data points 2, 3, and 4 in Table E.3 was reported in the T3 region and with fairly consistent results between the three samples, while Pentagon 2 indicates high temperature fault in mineral oil.

Table E.3—Duval Triangle ratios for unintentional core ground

Data point	% CH ₄	% C ₂ H ₄	% C ₂ H ₂
2	37.5%	61.9%	0.6%
3	37.2%	62.4%	0.5%
4	39.5%	59.8%	0.6%

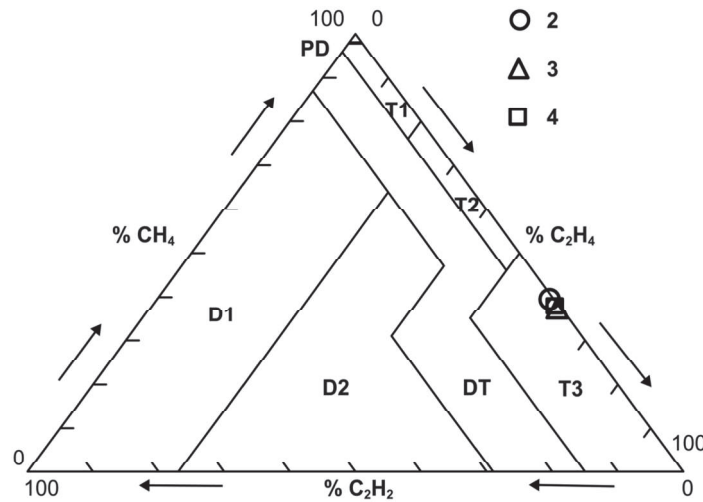


Figure E.1—Duval Triangle 1

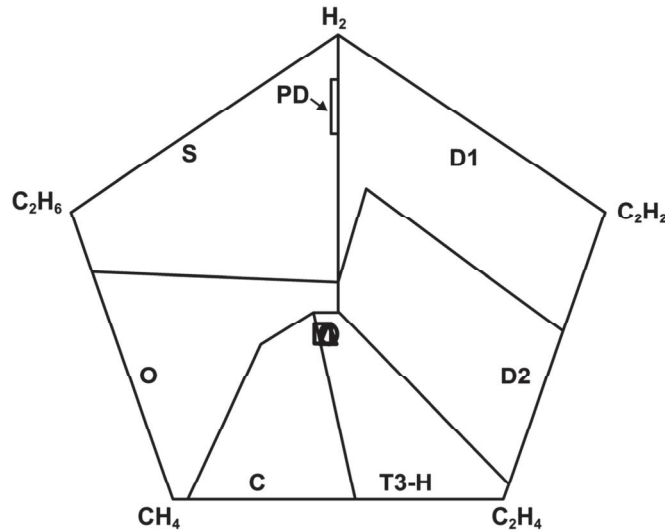


Figure E.2—Duval Pentagon 2

The result of the analysis was to repair the unintentional core ground by de-tanking the PA winding and replacing the core clamp bolts.

E.2 LV connections issues

The 161 kV to 13.8 kV, 30 MVA transformer in this case was placed into operation and immediately began generating combustible gases. The confirmation samples reported a similar DGA gas profile and increasing combustible gas concentrations. Two of the initial DGA samples are given in Table E.4.

Table E.4—Initial DGA results for connections issues

Data point	Sample dates	H ₂	CH ₄	C ₂ H ₆	C ₂ H ₄	C ₂ H ₂	CO	CO ₂	N ₂	O ₂
1	20-May-08	35	181	51	473	2	21	184	101 590	2 414
2	11-Jun-08	177	560	195	1,188	20	21	184	58 900	2 104

Table E.4 shows the initial DGA sample results (samples taken after the transformer was first energized) and indicate that combustible gas concentrations are above the Table 2 values for $O_2/N_2 \leq 0.2$ in the transformer age category of 1 to 10 years. The confirmation sample (data point 2) confirms the active gassing source with deltas above Table 3 for a Status 3 and for CH₄ and C₂H₄ a case of extreme DGA (see 6.1.2.4).

The transformer OEM was involved in the investigation and opted for an internal inspection. The electrical testing and internal inspection did not find the gassing source so the transformer was returned to service with an increased sampling frequency. The transformer was returned to Status 2 and it was closely monitored.

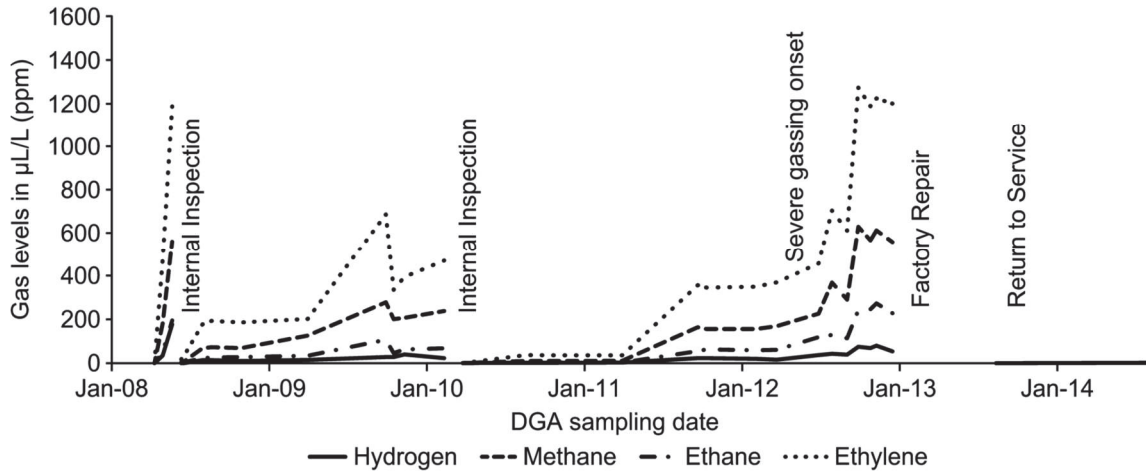


Figure E.3—DGA evolution from initial startup to repair

The Duval Triangle diagnostic method ratios, calculated in Table E.5 and plotted in Figure E.4, indicated an elevated temperature in the T3 region. The carbon monoxide for this transformer ranged between 20 $\mu\text{L/L}$ (ppm) and 40 $\mu\text{L/L}$ (ppm). The lack of carbon monoxide and carbon dioxide leads one to presume that there were no significant amounts of cellulose material, like insulation paper, near the fault. The OEM performed electrical tests, which eliminated concerns about an unintentional core ground. There continued to be a concern with a loose or high resistance connection.

Table E.5—Duval Triangle ratios

Data point	1	2
Sample date	20-May-08	11-Jun-08
% CH ₄	28%	32%
% C ₂ H ₄	72%	67%
% C ₂ H ₂	0%	1%

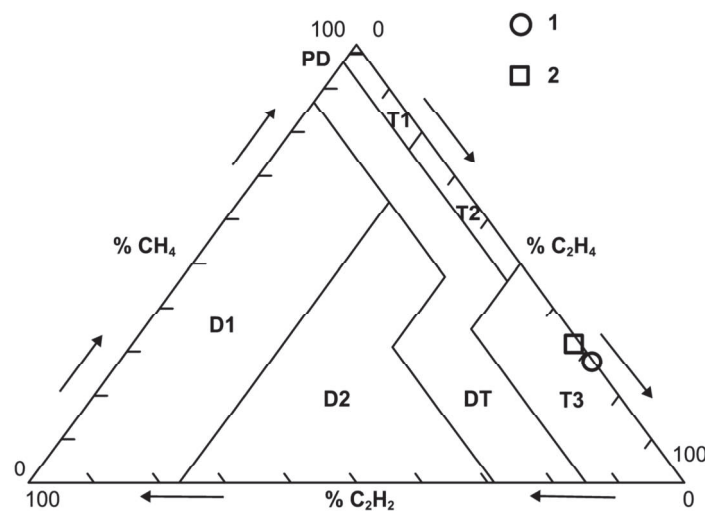


Figure E.4—Duval Triangle 1

Two years later, the transformer received a second internal inspection by the OEM after a period of higher gas generation rate, still without finding the gassing source, and was returned to service. After five years of

operation, with similar DGA gas profiles and sporadic gassing that appears to follow periods of higher electrical loads, the transformer was returned to the factory following a period of high gassing rate. See Table E.6 and Figure E.3.

Table E.6—Final DGA combustible gas concentrations in $\mu\text{L/L}$ (ppm) prior to factory repair

Data point	Sample dates	H ₂	CH ₄	C ₂ H ₆	C ₂ H ₄	C ₂ H ₂	CO	CO ₂	O ₂	N ₂	NEI _{Oil}
1	25-Apr-12	16	169	61	369	0	48	540	6 203	85 528	2.56
2	24-Jul-12	37	226	119	456	0	23	292	8 550	72 084	3.40
3	28-Aug-12	43	368	129	704	0	56	581	14 738	105 148	5.09
4	24-Sep-12	39	290	114	611	0	41	429	7 748	58 216	4.32
5	24-Oct-12	75	629	242	1,274	1	55	493	7 202	70 047	9.13
6	16-Nov-12	69	566	246	1,189	0	47	457	5 574	65 599	8.52

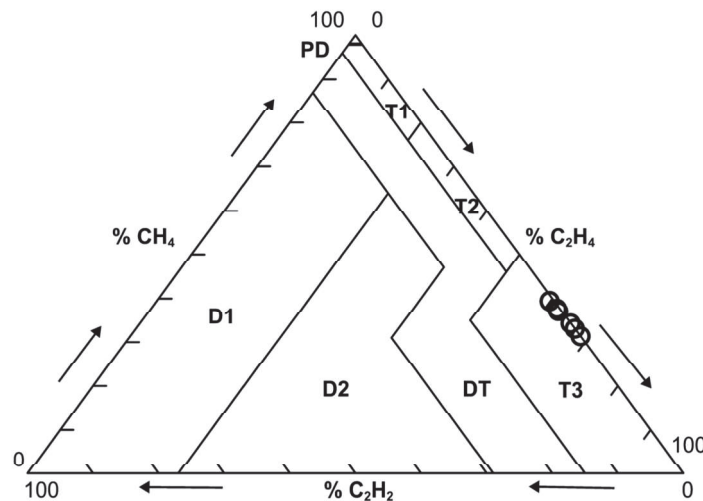


Figure E.5—Duval Triangle 1 for data prior to third investigation

Table E.6 contains DGA results of the large change in combustible gas concentrations, which prompted the transformer's removal from service and its return to the factory for inspection and untanking. Figure E.5 is the Duval Triangle 1 for the same data, indicating a T3 fault, same as previous occurrences. A significant development, which led to the decision to return the transformer to factory, was the reporting of a trace amount of acetylene and a large change in ethylene. The calculated NEI_{Oil} (see Annex F) for data point 1 is 2.56, which increases over the next several samples to reach a maximum of 9.13 at data point 5, indicating a deterioration of the gassing source. The data point 6 sample was a confirmation sample and the laboratory observed a trace amount of acetylene on the gas chromatogram chart that was below the minimum level of detection.

The transformer was untanked and faulty low voltage compression fittings were found. The cellulose insulation wrap was charred and falling apart from the heat generated by the high resistance connections. The low voltage compression fittings were replaced, and the transformer was returned to service.

E.3 Internal transformer arcing causes relay protective action

Background—The transformer in this case study supplies a municipal distribution substation, so the loss of the transformer does not represent a significant loss-of-energy-not-served exposure in the event of a failure. Typically, an annual sample frequency is recommended for this equipment application with the routine sample being taken in August. The August 2015 sample reported no abnormal results so the next routine sample was scheduled for the next year.

Table E.7 Data Point 1 from August 2015 routine sample analysis reported an oxygen to nitrogen ratio of 0.03, which is consistent with previous samples. This is an important consideration when trending the results from historic samples. The carbon dioxide and carbon monoxide gas concentrations are low and consistent with previous sample, which indicates normal aging of the cellulose insulating material. Carbon oxides increase over time as the cellulose and insulating liquid ages, which is expected, so they are monitored for large changes. A large increase in carbon dioxide is consistent with accelerated cellulose rate of aging. There are low amounts of combustible gases like methane, ethane, and ethylene which are expected either through errors in the sample analysis process or previous exposure to operating temperatures. There were no recommendations made to the equipment owner based on the Data point 1 (August 2015) sample results, which is in Status 1.

Technical Explanation—The electrical transformer is a 39-year-old transformer rated 161 kV to 69 kV with a 13.8 kV tertiary winding and a base capacity of 48 MVA. The transformer preservation system used a sealed tank design with a nitrogen blanket, so the Table 3 $O_2/N_2 \leq 0.2$ and the ≥ 30 age in years category is used for the evaluation.

The automatic differential current protection relay removed the transformer from service on December 7, 2015. There were no external indications for the protective relay trip cause and the electrical tests did not report results that exceeded the expected ranges. The electrical tests included a turn-to-turn ratio, insulation resistance, winding resistance, power factor, and excitation current electrical tests. A cursory internal inspection of the transformer main tank did not find the reason for the electrical trip. The transformer was 39 years in operation at the time of the fault. The tripping investigation sample (data point 2 of Table E.7) confirms the active gassing source with the C_2H_2 level above the Table 2 norm and with the deltas above Table 3 norms for a DGA Status 3.

Data Point 2 was taken about 12 hours after receiving a transformer protective electrical trip for differential current. The combustible gases and carbon dioxide gas concentrations reported in the post trip Sample 2 are similar to the historical results with the notable exception of acetylene. Acetylene is normally associated with arcing activity. The other combustible gases are near the historical ranges with the concentrations at or near the laboratory minimum reporting levels. The generation of acetylene combined with the transformer trip warranted additional electrical testing and possibly an internal inspection. A DGA confirmation sample would normally be requested, but there was a need to return the transformer to service.

Data Point 3 was taken after completing the electrical testing and internal inspection. The liquid was reclaimed which included degassing the insulating liquid. A limited amount of residual gases was expected to be seen in subsequent samples even if the gassing source became inactive. The transformer was energized and immediately tripped from an electrical protection relay. Data Point 4 was taken shortly after the transformer tripped the second time from the protective relay action. Data Point 4 reported increases in the combustible gas concentrations with a similar gas profile to Data Sample 2. Data Point 4 following the second protective relay action remained in Status 3, with C_2H_2 , a case of extreme DGA, requiring immediate action (see 6.1.2.4).

Table E.7—DGA history in $\mu\text{L/L}$

Data point	Sample dates	H ₂	CH ₄	C ₂ H ₆	C ₂ H ₄	C ₂ H ₂	CO	CO ₂	N ₂	O ₂
1	8-Aug-15	0	16	35	3	0	16	954	65 400	117
2	7-Dec-15	40	26	41	17	29	33	974	74 232	254
3	17-Dec-15	0	2	2	1	1	4	95	3 770	388
4	18-Dec-15	154	60	12	124	163	82	126	112 000	1 330

Analysis—The standard industry practices of annual sample frequency for transformer insulating liquid is widely used with some exceptions for equipment with a significant financial impact. This transformer was 39-years-old and even though the actual fault is not known at this time, it is likely a breakdown of the insulation system. End-of-life failures due to cellulose aging can be sudden and without warning precursors seen in other types of transformer faults.

One method to identify faults is the Duval Triangle method. This method plots calculated ratios show in Table E.7 from the sample results.

The Duval Triangle analysis method placed the DGA gas profile in the D2 region and it identifies high energy electrical arcing as the possible gassing source. The low amount of combustible gas concentrations may indicate a fault deep in the windings. The gases could be sequestered in the mineral oil and cellulose material surrounding the fault. Another thought is a limited amount of insulating liquid between winding turns meant there was no lower temperature zones to generate other gases. There has not been a forensic tear down inspection on the transformer to identify the fault location and type.

Table E.8—Duval Triangle ratios

Data point	Sample date	%CH ₄	%C ₂ H ₄	%C ₂ H ₂
2	7-Dec-15	36%	24%	40%
4	18-Dec-15	17%	36%	47%

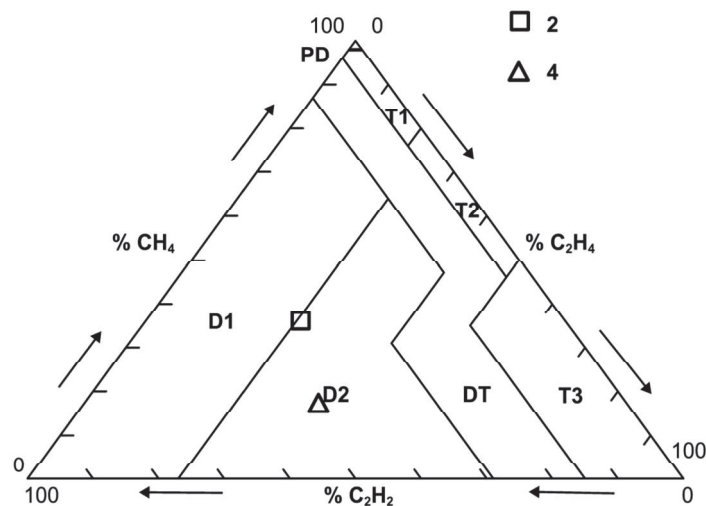


Figure E.6—Duval Triangle 1

E.4 De-energized tap changer (DETC) high resistance connection

Background—This case study reports the dissolved gas results for a power plant auxiliary transformer (unit transformer) that is directly connected to the electrical generator. The transformer is a 1995 vintage. An unexpected transformer failure would cause a unit trip shutting down the power plant until the transformer is switched out of the circuit and plant power restored through a station service power transformer. The unit transformer (auxiliary power plant transformer directly connected to the generator) was on a six months DGA sample frequency because of the potential economic impact to plant operation in the event of an unexpected failure.

Some transformer designs use a manual tap-changing device on the high-voltage windings that allow insertion or removal of windings to adjust the transformer voltages to the system specifications. Some transformer designs are equipped with a manually-operated tap changing device (operated with the transformer de-energized), placed in the high voltage winding that allows the addition or subtraction of turns to adjust the voltage output to the system. These DETCs (De-Energized Tap Changers) are designed with both stationary and moveable contacts connected via a shaft to an external operating handle. The mechanism cannot be operated on an energized transformer, so the mechanism is typically locked in place. Component movement can displace pressboard or tear insulation paper which can decrease the insulation resistance. A high-resistance electrical connection can produce an elevated temperature, which is reported with a DGA.

Technical explanation—The formation of a high-resistance connection can be from improper contact pressure, contact material deterioration, film formation on contact surface or improper operation of the mechanism. The high-resistance connection generates heat that forms combustible gases like hydrogen, methane, ethane and ethylene. The leads connecting the DETC to the windings are typically cellulose insulation wrapped leads so elevated temperatures can also generate small amounts of carbon gases like carbon monoxide and carbon dioxide. The elevated temperatures will cause the contacts to deteriorate and carbon to form on contact surfaces that reduce contact surface areas and generate higher temperatures. This failure mechanism reports increasing rates of gas generation over time.

Table E.9—DGA results for a high resistance connection in $\mu\text{L/L}$ (ppm)

Data point	Sample date	H ₂	CH ₄	C ₂ H ₆	C ₂ H ₄	C ₂ H ₂	CO	CO ₂	N ₂	O ₂
1	26-Jan-10	3	9	3	3	0	653	3 603	76 587	6 085
2	9-Dec-10	14	67	26	119	1	705	4 002	76 256	6 423
3	22-Mar-11	18	80	32	149	1	727	3 951	78 592	7 188
4	14-Jun-11	13	66	33	243	0	816	3 531	45 599	1 431

Analysis—In Table E.9, data point 1 shows the typical routine sample that reported DGA results consistent with historic samples. The subsequent routine sample from Table E.8, data point 2 reported a change in the DGA gas profile and combustible gas concentrations, which indicated an abnormal gassing profile. The transformer was 15 years in operation at the time of the abnormal DGA. Table E.9 shows the DGA sample ethylene (C₂H₄) is above the Table 1 O₂/N₂ ≤ 0.2 value for a transformer in the 10 year to 30 year category. The Table E.9 DGA ethylene (C₂H₄) result is also above the Table 2 concentrations for the same category. The confirmation sample (data point 3) and monitoring sample (data point 4) confirms the active gassing source with multi-point sample rate of change exceeding Table 4 for a Status 3. The data point 2 concentrations exceed Table 1 and Table 3 norms, so a confirmation sample was taken as Table E.9 data point 3. The data point 4 sample, dated June 14, 2011, reported an increase in the ethylene gas concentration of 94 $\mu\text{L/L}$ (ppm). An increasing gas rate of change is normally associated with a deteriorating condition like an increase in gassing temperature source.

Table E.10—Delta $\mu\text{L/L}$ (ppm v/v) between successive samples

Data point	Sample dates	H ₂	CH ₄	C ₂ H ₆	C ₂ H ₄	C ₂ H ₂	CO	CO ₂
1	26-Jan-10	NA	NA	NA	NA	NA	NA	NA
2	9-Dec-10	11	56	23	116	1	52	338
3	22-Mar-11	4	13	6	30	0	22	765
4	14-Jun-11	-1	-14	1	96	-1	89	-5757

The Duval Triangle ratios are calculated in Table E.11 with data points 2 and 3 reporting similar profiles. Figure E.6 Duval ratio plot places the gassing source temperature in the T3 region (>700 °C). A comparison of the Duval Triangle results given in Table E.11 indicates a possible deterioration in the unit’s condition.

Table E.11—Duval Triangle ratios

Data point		2	3	4
Date		9-Dec-10	22-Mar-11	14-Jun-11
% CH ₄		36%	35%	21%
% C ₂ H ₄		64%	65%	79%
% C ₂ H ₂		1%	0%	0%

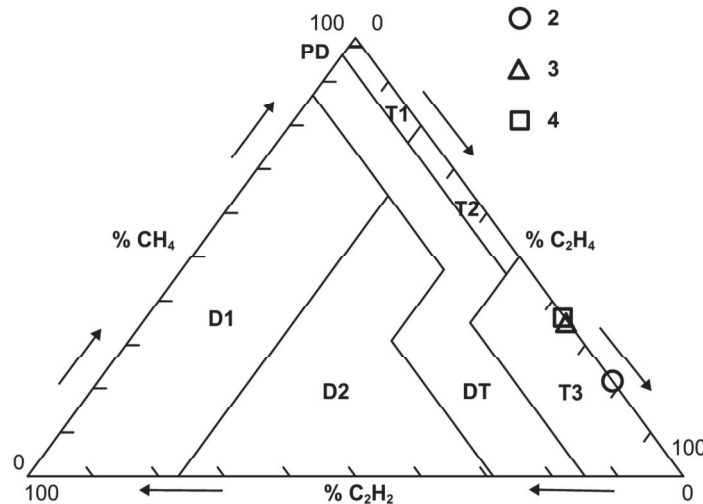


Figure E.7—Duval Triangle 1

Summary—The power plant was shut down for a scheduled outage during which the transformer was electrically tested and internally inspected for indications of the gassing source. The DETC contacts were covered with coke formed from an elevated temperature. The winding insulation resistance should have indicated a change from historical results, but the test equipment current source may not have been sufficient to produce the abnormal result. The DETC contacts were removed from the circuit with the installation of shunts.

E.5 Broken connector on fuse holder

Background—The change in the DGA gas profile for a 1987 vintage 4 160/480 V, 500 KVA transformer was noted during a routine sample. This transformer supplied the compressor of a refrigeration system at a

food processing plant. The failure of this transformer could cause the loss of a large inventory of frozen food, so it was part of a DGA program despite its small size. The transformer has a sealed tank preservation system with a nitrogen blanket. The DGA gas profile indicated arcing activity that was confirmed with a second DGA sample. The large increase in carbon dioxide gas concentration was possibly due to burning cellulose material (paper insulation) or overload condition.

Technical explanation—This transformer was designed with fuse holders between the line connections and the 4 160 volt windings. The winding was connected to the fuse holder through bolted connections.

Table E.12 data point 1 was a routine sample, similar to previous samples, and presented no anomaly. The transformer was 18 years in operation at the time of the abnormal DGA so the $O_2/N_2 \leq 0.2$ norms for a transformer in the 10 year to 30 year category are referenced. For point 2, acetylene (C_2H_2) and ethylene (C_2H_4) results are above Table 2 norms. In fact, the C_2H_2 delta is typical of extreme DGA results (see 6.1.2.4), so a confirmation sample was taken (Table E.12, data point 3), which confirmed the increase.

The Duval Triangle Ratios for data point 2 and 3 are calculated in Table E.13 and give a D1 diagnostic.

Table E.12—DGA results for broken connector on fuse holder in $\mu\text{L/L}$ (ppm)

Data point	Sample date	H ₂	CH ₄	C ₂ H ₆	C ₂ H ₄	C ₂ H ₂	CO	CO ₂	N ₂	O ₂
1	11 Feb 2005	4	2	0	0	0	47	785	76 784	7715
2	23 Nov 2005	166	63	8	117	645	51	4435	64 414	16 502
3	15 Dec 2005	188	89	15	129	631	72	5769	64 189	16 338

Table E.13—Duval Triangle 1 ratios

Data point	2	3
	23-Nov-05	15-Dec-05
% CH ₄	8%	10%
%C ₂ H ₄	14%	15%
%C ₂ H ₂	78%	74%

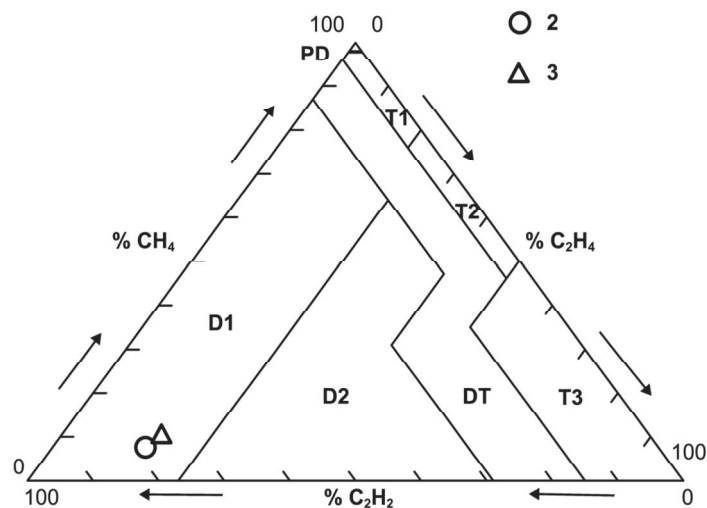


Figure E.8—Duval Triangle 1

Summary—The transformer was removed from service in the off-season during a scheduled outage period. The electrical winding resistance test reported the H1 to H0 resistance at about 240 mΩ compared to the other phases of near 160 mΩ, which isolated the gassing source to the H1–H0 winding. An internal inspection identified a broken fuse holder connection, which was repaired on site. The transformer insulating liquid was reclaimed and degassed. The unit was offline for one-day.

Annex F

(informative)

Evaluation of fault severity—alternative method

Recent research suggests an alternative approach to transformer DGA fault detection and severity assessment. Instead of comparing fault gas concentrations and rates with limits, the method employs indexes of the energy required to form the fault gas concentrations observed in a mineral oil sample. The indexes are responsive to all DGA-detectable fault types. The basic principle of the method is that active fault gas formation suggests an internal problem or overly stressful operating conditions, while absence of active fault gas formation is uninformative as to the state or condition of the transformer. Statistical models based on transformer DGA and failure data indicate that the additional risk of forced outage due to active gassing is roughly proportional to the amount of increase in the hydrocarbon gas energy index since the gassing began.

Low molecular weight hydrocarbon gases (methane, ethane, ethylene, and acetylene) dissolved in a transformer's mineral oil are formed primarily when the mineral oil is "cracked" by exposure to intense thermal or electrical stress associated with overloading or faults. Hydrogen is formed in the same way but, significant amounts of it can also be formed in other ways. The hydrocarbon gases, in the order listed above, are characteristically formed at increasingly high fault temperatures because of the different amounts of energy required to create a molecule of each gas from mineral oil. Methane is the primary hydrocarbon gas formed by PD and T1 faults. Ethane and (to a slightly lesser degree) methane are the primary gases formed by T2 faults, ethylene is the primary gas formed by T3 faults, and acetylene is associated almost exclusively with faults involving electrical arcing or sparking. The differential production of the hydrocarbon gases depending on fault energy is the basis for the Duval Triangle method of fault type identification.

Mineral oil decomposition at or near normal operating temperatures, can be caused by non-fault-related chemical and electrochemical reactions with oxygen, dissolved water, contaminants, or solid materials in contact with the mineral oil. Gas production of that nature—usually of hydrogen but sometimes of methane, ethane, or ethylene—is called "stray gassing." Gas production that is suspected to be stray gassing is to be excluded from consideration for the detection, assessment, and identification of faults. Likewise, when a transformer is suspected of losing fault gas by leakage or any other means, the fact of gas loss should be taken into account in DGA interpretation.

The carbon oxide gases, carbon monoxide (CO) and carbon dioxide (CO₂) are formed slowly by the gradual degradation of cellulosic insulation by dissolved water and oxygen, catalyzed by acidic byproducts of oxidation of the mineral oil. Arcing, partial discharge, and overheating of conductors in proximity to cellulose insulation can rapidly produce large amounts of carbon oxides and hydrogen by carbonizing the cellulose.

The hydrocarbon gases methane, ethane, ethylene, and acetylene are formed in mineral oil primarily as the result of fault energy decomposing the mineral oil. Recent research has shown that a Normalized Energy Intensity calculated from those concentrations (NEI_{oil}) is useful for judging relative severity of faults affecting the liquid insulation. Similarly, another Normalized Energy Intensity quantity (NEI_{paper}) calculated from the concentrations of CO and CO₂ is useful for assessing faults affecting the solid insulation, especially paper wound around conductors. The coefficients of the gas concentrations in the NEI formulas below are the respective standard heats of formation of the gases from a typical mineral oil molecule (NEI_{oil}) or a typical monomer of cellulose (NEI_{paper}).

Computation of NEI_{oil} :

$$NEI_{oil} = (77.7 \times [CH_4] + 93.5 \times [C_2H_6] + 104.1 \times [C_2H_4] + 278.3 \times [C_2H_2]) / 22400 \quad (F.1)$$

Computation of NEI_{paper} :

$$NEI_{paper} = (101.4 \times [CO] + 30.2 \times [CO_2]) / 22400 \quad (F.2)$$

In Equation F.1 and Equation F.2, the chemical formulas in brackets denote gas concentrations in $\mu\text{L/L}$ (ppm), corrected to standard temperature and pressure (273.15 K and 101.325 kPa). The units of NEI are kilojoules per kiloliter (kJ/kL). In cases where significant ethane stray gassing is suspected, the quantity NEI_{3oil} , calculated by setting the ethane concentration to zero in the NEI_{oil} formula, may be used in place of NEI_{oil} . For brevity, only NEI_{oil} is mentioned below, but the discussion is applicable to NEI_{3oil} .

A transformer that is actively producing fault gas may need investigation, surveillance, or mitigative action appropriate to the apparent fault type (determined from recent gas increments by means of the Duval Triangle or other fault identification method) and the amount of increase in NEI since the gassing began. Accelerating NEI increase or evolution of the fault type from lower-energy faults (PD, T1, T2) to higher-energy faults (T3, D1, D2) may signal that the problem is worsening, with the potential of reaching a runaway condition and failing the transformer.

The response of NEI_{oil} to all fault types has been shown to be sufficiently uniform that consideration of individual hydrocarbon fault gases is not necessary for fault severity assessment. However, separate attention should be paid when carbon oxide gas (CO or CO_2) are present. If NEI_{paper} is increasing, especially if the CO_2/CO ratio is also significantly decreasing, there may be a fault affecting insulating paper. Furthermore, since acetylene production is associated primarily with sparking or arcing, which should not be ongoing in a transformer in good condition under normal operating circumstances, some sites may wish to have a policy of watching for active production of acetylene, especially at low levels where NEI_{oil} is not changing very much.

Experience with this NEI-based method at a large US electric utility suggests that an NEI_{oil} increment of 0.5 or an NEI_{3oil} increment of 0.3 over any time interval should raise concern for the transformer's condition, and larger increments warrant correspondingly more concern. Active gassing of that magnitude should not be ignored unless its cause is understood to be harmless.

Example 1—A power transformer experienced a NEI_{oil} increase of 0.43 over a sampling interval of 550 days, then 1.76 over a sampling interval of 365 days, and then 3.81 over a sampling interval of 400 days. The apparent fault type was T3 in each case, based on gas increments plotted on the Duval Triangle.

After an NEI_{oil} increment of 0.43 (close to the suggested limit of 0.5) was detected, additional sampling could have been scheduled after, say, 90 days to check for confirmation of active gassing, following which investigation and possible infrared inspection or other testing could have been performed to identify the cause of the gassing so that it could be dealt with. That, however, was not done in this case. With the NEI_{oil} increment more than doubling as of each of the next two routine annual samples and getting very large, urgent investigation and possible mitigation would need to be considered. The level of concern would be even higher if NEI_{paper} trended upward or if CO_2/CO trended downward during the time that NEI_{oil} was increasing, because of the possibility of paper insulation being degraded by the process causing the gassing.

Example 2—This example is a re-analysis of the LV connection issues case study presented in E.2. In the initial period, NEI_{oil} increased from 3.06 on 20 May 2008 to 8.53 on 11 June 2008, an increase of 5.47 kJ/kL (eleven times the suggested limit) in less than a month, which is a very severe event. The fault type, identified by applying the Duval Triangle to the respective methane, ethylene, acetylene gas

increments of 380, 715, 18, is T3. No suspicious changes in NEI_{paper} or CO_2/CO were observed. As noted in the case history, an internal inspection of the transformer revealed nothing at this point. Later, following a similar gassing incident, the transformer was de-tanked at the factory, and internal damage was discovered. Some charring of cellulose conductor insulation was found, but the quantity of paper affected was evidently insufficient to change carbon oxide gas concentrations by much over five years.

Annex G

(informative)

Historical material

This annex contains text removed from the previous version of this document (IEEE Std C57.104-2008). The content of this annex is not part of IEEE Std C57.104 and is presented here for documentation purpose only. The number in parenthesis in clause heads refers to the clause number of IEEE Std C57.104-2008). Numbers within text might refer to the 2008 numbering or the appendix numbering.

NOTE—Some of the information presented here could be obsolete and no longer represent the generally accepted opinion of most experts on DGA interpretation. The text in this annex was not updated in any manner in regard of IEEE Std C57.104 2008, to the exception of the numbering of clauses, tables, and figures.

G.1 (4) General theory

The two principal causes of gas formation within an operating transformer are thermal and electrical disturbances. Conductor losses due to loading produce gases from thermal decomposition of the associated oil and solid insulation. Gases are also produced from the decomposition of oil and insulation exposed to arc temperatures. Generally, where decomposition gases are formed, principally by ionic bombardment, there is little or no heat associated with low energy discharges and partial discharge.

G.1.1 (4.1) Cellulosic decomposition

The thermal decomposition of oil-impregnated cellulose insulation produces carbon oxides (CO, CO₂) and some hydrogen or methane (H₂, CH₄) due to the oil (CO₂ is not a combustible gas). The rate at which they are produced depends exponentially on the temperature and directly on the volume of material at that temperature. Because of the volume effect, a large, heated volume of insulation at moderate temperature will produce the same quantity of gas as a smaller volume at a higher temperature.

G.1.2 (4.2) Oil decomposition

Mineral transformer oils are mixtures of many different hydrocarbon molecules, and the decomposition processes for these hydrocarbons in thermal or electrical faults are complex. The fundamental steps are the breaking of carbon-hydrogen and carbon-carbon bonds. Active hydrogen atoms and hydrocarbon fragments are formed. These free radicals can combine with each other to form gases, molecular hydrogen, methane, ethane, etc., or can recombine to form new, condensable molecules. Further decomposition and rearrangement processes lead to the formation of products such as ethylene and acetylene and, in the extreme, to modestly hydrogenated carbon in particulate form.

These processes are dependent on the presence of individual hydrocarbons, on the distribution of energy and temperature in the neighborhood of the fault, and on the time during which the oil is thermally or electrically stressed. These reactions occur stoichiometrically; therefore, the specific degradations of the transformer oil hydrocarbon ensembles and the fault conditions cannot be predicted reliably from chemical kinetic considerations. An alternative approach is to assume that all hydrocarbons in the oil are decomposed into the same products and that each product is in equilibrium with all the others. Thermodynamic models permit calculation of the partial pressure of each gaseous product as a function of temperature, using known equilibrium constants for the relevant decomposition reactions. An example of the results of this approach is shown in Figure G.1 due to Halstead. The quantity of hydrogen formed is

relatively high and insensitive to temperature; formation of acetylene becomes appreciable only at temperatures nearing 1000 °C.

Formations of methane, ethane, and ethylene each also have unique dependences on temperature in the model. The thermodynamic approach has limits; it must assume an idealized but nonexistent isothermal equilibrium in the region of a fault, and there is no provision for dealing with multiple faults in a transformer. However, the concentrations of the individual gases actually found in a transformer can be used directly or in ratios to estimate the thermal history of the oil in the transformer from a model and to adduce any past or potential faults on the unit. As the simplest example: the presence of acetylene suggests a high temperature fault, perhaps an arc, has occurred in the oil in a transformer; the presence of methane suggests that—if a fault has occurred—it is a lower energy electrical or thermal fault. Much work has been done to correlate predictions from thermodynamic models with actual behavior of transformers.

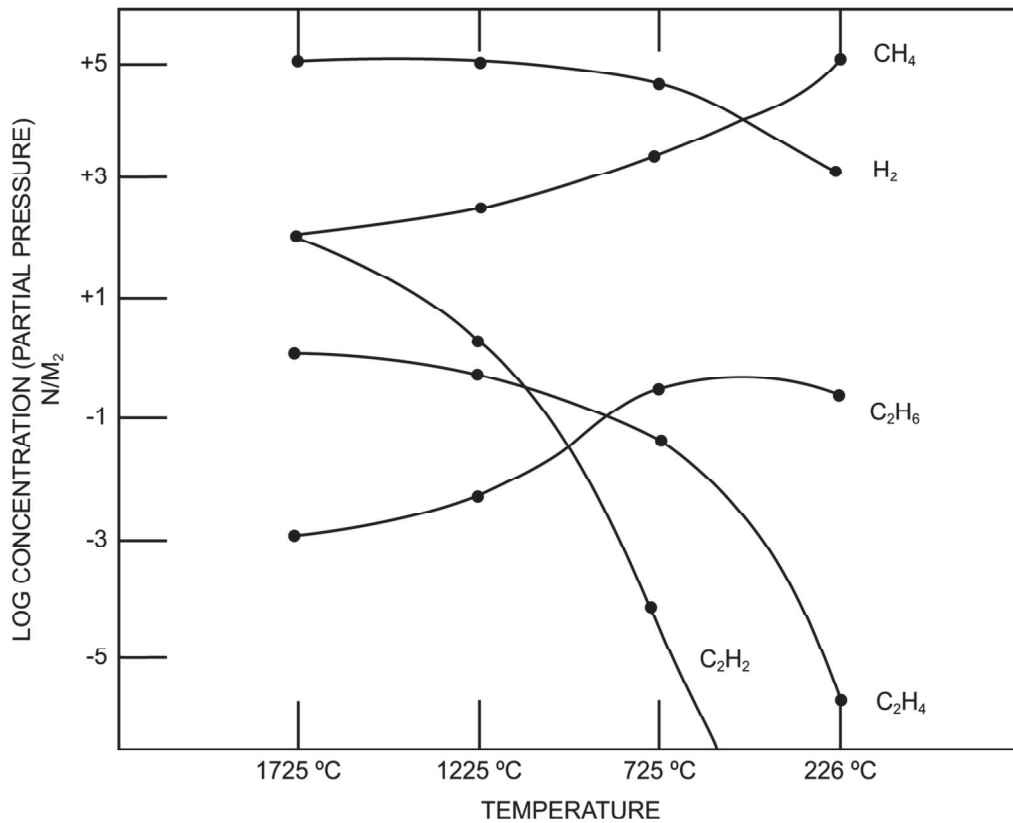


Figure G.1—(Figure 1) Halstead's Thermal Equilibrium Partial Pressures as a function of temperature

Attempts to assign greater significance to gas than justified by the natural variability of the generating and measuring events themselves can lead to gross errors in interpretation. However, in spite these gas-generating mechanisms are the only existing basis for the analytical rules and procedures developed in this guide. In fact, it is known that some transformers continue to operate for many years in spite of above average rates of gas generation.

G.2 (6.3) Determining the gas space and dissolved gas-in-oil equivalents

All samples of gas from the gas blanket above the oil should be taken in accordance with ASTM D 3305.

Gas space and oil equivalents are used to compare the results of analysis of the gas space (TCG) with results from analysis of the gases dissolved in the oil (TDCG). Comparisons of gas ratios obtained from the

gas space can then be compared to similar ratios of gases extracted from the oil. It should be noted that the calculated equivalent values of TCG_e and experimentally measured values of TCG probably do not show close agreement, since the equation for obtaining the equivalents assumes the existence of equilibrium between the gas blanket and the oil. This condition may not exist, particularly in the case of an actively progressing fault or in sample from gas relay. However, the equation is valuable for the determination of a limiting value for the expected total combustible gas concentration in the gas blanket. The dissolved gas equivalent of the TCG_e is obtained using Equation G.1:

$$TCG_e = \sum_{C_1}^{C_n} \left[\frac{\frac{F_c}{B_c}}{\sum_{G_1}^{G_n} \frac{F_g}{B_g}} \right] \times 100 \quad (G.1)$$

where:

- TCG_e = An estimate of the percent of combustible gas in the gas space
- C_x = Each combustible gas dissolved in oil
- G_x = Each gas dissolved in oil (combustible and noncombustible)
- F_c = The concentration expressed in $\mu\text{L/L}$ (ppm) of combustible gas g dissolved in oil
- B_c = The Ostwald solubility coefficient of combustible gas g
- F_g = The concentration of a particular gas dissolved in oil
- B_g = The Ostwald solubility coefficient of particular gas

Table G.1—Ostwald coefficients

Gas	Ostwald Coefficient (B) (25°C)
H ₂ ^a	0.0429
O ₂	0.138
CO ₂	0.900
C ₂ H ₂ ^a	0.938
C ₂ H ₄ ^a	1.35
N ₂	0.0745
CO ^a	0.102
C ₂ H ₆ ^a	1.99
CH ₄ ^a	0.337

NOTE—Ostwald coefficients are for an oil with a density of 0.880 at STP.

^a Combustibles

G.3 (6.5.1) Determining the transformer condition and operating procedure utilizing TCG in the gas space

When sudden increases in the combustible gas concentrations or generating rates in the gas space of an operating transformer occurs and an internal fault is suspected, the procedure recommended in Table G.2 should be used.

Table G.2 indicates the recommended initial sampling intervals and operating procedures for various levels of TCG (in percent).

Once the source of gassing is determined by analysis, inspection, consultation, or combinations thereof and the risk has been assessed, then engineering judgment should be applied to determine the final sampling interval and operating procedure.

Table G.2—Actions based on TCG and TCG rate

	TCG levels (%)	TCG rate (%/day)	Sampling intervals and operating procedures for gas generation rates	
			Sampling interval	Operating procedures
Condition 4	≥5	>.03	Daily	Consider removal from service. Advise manufacturer
		.01-.03	Daily	
		<.01	Weekly	Exercise extreme caution. Analyze for individual gases. Plan outage. Advise Manufacturer
Condition 3	<5 to ≥2 >-2 to <5	>.03	Weekly	Exercise extreme caution. Analyze for individual gases. Plan outage. Advise manufacturer.
		.01-.03	Weekly	
		<.01	Monthly	
Condition 2	<2 to ≥.5 >-0.5 to <2	>.03	Monthly	Exercise caution. Analyze for individual gases. Determine load dependence.
		.03-.01	Monthly	
		<.01	Quarterly	
Condition 1	<0.5	>.03	Monthly	Exercise caution. Analyze for individual gases. Determine load dependence.
		.01-.03	Quarterly	
		<.01	Annual	Continue normal operation.

Example—A transformer has a TCG level of 0.4% and is generating gas at a constant rate of 0.035% TCG per day. Table G.2 indicates Condition 1. It should be sampled monthly, and the operator should exercise caution, analyze for individual gases, and determine load dependence

G.4 (6.7.1) Evaluation of possible fault type by the Doernenburg Ratio method

The Doernenburg method suggests the existence of three general fault types. The method utilizes gas concentrations from which Ratios 1, 2, 3, and 4 are calculated. The step-by-step procedure (flow chart) is shown in Figure G.2.

The values for these gases are first compared to special concentrations—L1—Table G.3 (see Steps 2, 3, and 4 in Figure G.2) to ascertain whether there really is a problem with the unit and then whether there is sufficient generation of each gas for the ratio analysis to be applicable. Then the ratios in the order Ratio 1, Ratio 2, Ratio 3, and Ratio 4 are compared to limiting values, providing a suggested fault diagnosis as given in Table G.2 This table gives the limiting values for ratios of gases dissolved in the oil and gases obtained from the transformer gas space or gas relay.

The flow chart in Figure G.2 illustrates the step-by-step application of the Doernenburg ratio method for gases extracted from the transformer oil only. Exactly the same procedure is followed for gases obtained from the gas space or gas relays, except the limiting values for the ratios will be those appropriate for gas space (Table G.4).

Descriptions of the steps indicated in Figure G.2:

- Step 1: Gas concentrations are obtained by extracting the gases and separating them by chromatograph.
- Step 2: If at least one of the gas concentrations [in $\mu\text{L/L}$ (ppm)] for H_2 , CH_4 , C_2H_2 , and C_2H_4 exceeds twice the values for limit L1 (see Table G.4) and one of the other two gases exceeds the values for limit L1, the unit is considered faulty; proceed to Step 3 to determine validity of the ratio procedure.
- Step 3: Determining validity of ratio procedure: If at least one of the gases in each ratio R1, R2, R3, or R4 exceeds limit L1, the ratio procedure is valid; otherwise, the ratios are not significant, and the unit should be resample and investigated by alternate procedures.
- Step 4: Assuming that the ratio analysis is valid, each successive ratio is compared to the values obtained from Table G.4 in the order R1, R2, R3, and R4.
- Step 5: If all succeeding ratios for a specific fault type fall within the values given in Table G.4, the suggested diagnosis is valid.

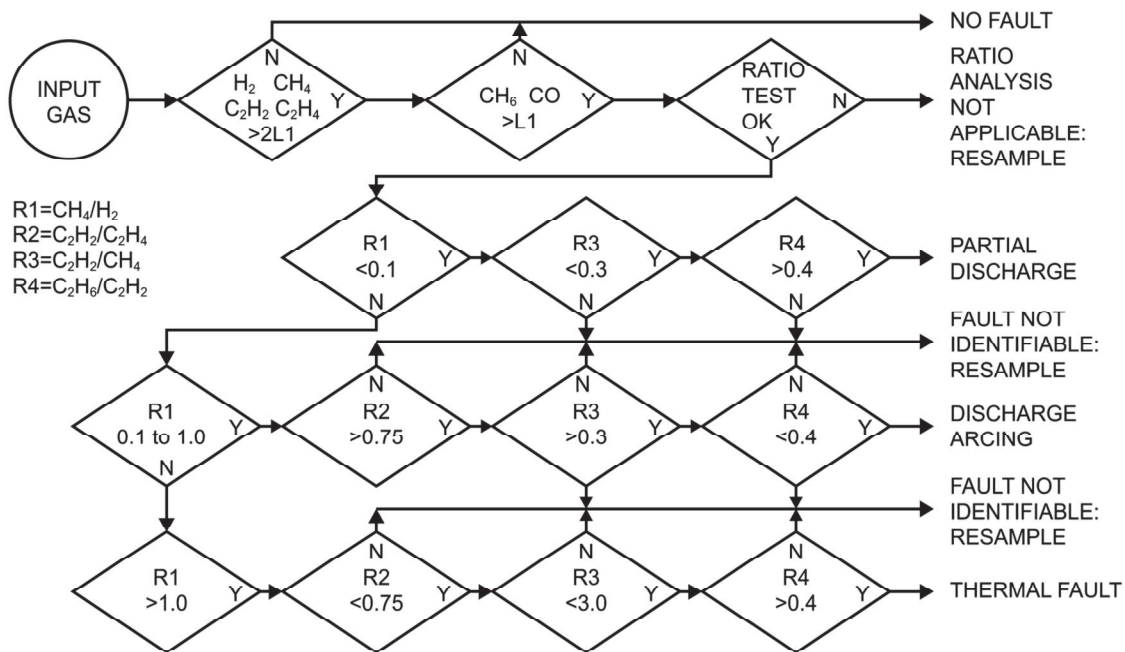


Figure G.2—(Figure 4) Doernenburg ration method flow chart

Table G.3—Limit concentrations of dissolved gas

Key gas	Concentrations L1 ($\mu\text{L/L}$ (ppm v/v))
Hydrogen (H_2)	100
Methane (CH_4)	120
Carbon Monoxide (CO)	350
Acetylene (C_2H_2)	1
Ethylene (C_2H_4)	50
Ethane (C_2H_6)	65

Table G.4—Ratios for key gases—Doernenburg

Suggested fault diagnosis	Ratio 1 (R1) CH_4/H_2		Ratio 2 (R2) $\text{C}_2\text{H}_2/\text{C}_2\text{H}_4$		Ratio 3 (R3) $\text{C}_2\text{H}_2/\text{CH}_4$		Ratio 4 (R4) $\text{C}_2\text{H}_6/\text{C}_2\text{H}_2$	
	Oil	Gas space	Oil	Gas space	Oil	Gas space	Oil	Gas space
1—Thermal decomposition	>1.0	>0.1	<0.75	<1.0	<0.3	<0.1	>0.4	>0.2
2—Partial discharge	<0.1	<0.01	Not significant		<0.3	<0.1	>0.4	>0.2
3—Arcing (high intensity PD)	>1.0 <1.0	>0.01 <0.1	>0.75	>1.0	>0.3	>0.1	<0.4	<0.2

G.5 (7) Instruments for detecting and determining the amount of dissolved gases present

G.5.1 (7.1) Portable instruments

Many of the gases generated by a possible malfunction in an oil-filled transformer are combustible. The on-site detection and estimation of combustible gases in the transformer in the field using a portable combustible gas meter can be the first and the easiest indication of a possible malfunction, and it may form the basis for further testing or an operating decision.

When a more accurate determination of the total amount of combustible gases or a quantitative determination of the individual components is desired, a laboratory analytical method using a gas chromatograph or mass spectrometer may be used.

WARNING

Gases generated in transformers can be explosive.

Strict precautions must be observed when sampling the gases from the transformer.

G.5.2 (9.4) Determination of individual gases present in the gas blanket

Analysis of the individual gases present in the gas blanket above the oil may be made by using ASTM D3612, beginning at Section 10 of that standard. Section 13.1 and Section 13.2 of ASTM D3612 are not applicable in this case.

Annex H

(informative)

Bibliography

The purpose of this annex is to present a number of reference materials for the purpose of identifying a good cross-section of the most relevant resource material(s) reviewed and considered in the development of the art and science of Dissolved Gas Analysis (DGA) of transformer insulating liquid. This annex also serves as a historical archive of papers and other resources that were developed, written and documented throughout the course of the history of mineral oil use as a dielectric medium in power transformers.

Bibliographical references are resources that provide additional or helpful material but do not need to be understood or used to implement this standard. Reference to these resources is made for informational use only.

H.1 Gas evolution

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I&E Exhibit 4



TRN PNS000500001042 / BOT MAIN

Equipment	PNS000500001042	Spare	False
Serial No.	SDV301704	Tank	BOT MAIN
Apparatus type	TRN	Norms used	TRN_IEEE_INC_69KV
Equipment group name	Transmission	DGA result	1↗4
Owner	3000 - Penelec	Moisture result	1→1
Region	305 - Warren	FQ result	1↗4
Substation	PNS-DEL EQU WARREN	Trace elements result	0→0
Norms	TRN_IEEE_INC_69KV	Particle analysis result	0→0
Description	1 BK 34-12 KV (NON TYPE U BUSHINGS)	PCB result	0↗1
Manufacturer	Westinghouse Electric	Furan result	0→0
Model	Unknown	Oil test status	UNREVIEWED
In service	True		

This transformer has a Reliability-based dissolved gas analysis report available. That report gives deeper insight into the status of the transformer by analyzing the entire DGA history and by comparing it with statistical models of similar transformers. Click [here](#) for more details on the method and [here](#) to view the report for this transformer.

Last Analysis Done On 2025-11-05

Last sample date	2023-05-03
Tank last modified date	2025-11-05
Equipment last modified date	2024-08-02
Norms last modified date	2000-01-01
Last analysis date	2025-11-05
Read-only samples	0
Excluded samples	1
Total samples	28

Sample Remarks

Sampled	Container	Reviewer remarks
2023-08-28 12:00:00	DGA0007144	Failed Transformer - TX Out of Service - Bad TTR Results - Report to Dave Thomas
2023-05-03 12:06:00	BETA000070689	DGA analyzed twice to confirm increase in gas.
2023-05-03 12:05:00	BETA000070687	DGA analyzed twice to confirm increase in gas.
2023-05-03 12:01:00	DGA0014851	DGA analyzed twice to confirm increase in gas.
2022-03-01 12:01:00	DGA0007744	.



Dissolved Gas Analysis

Lab report number	XA78821	XA66804	XA56621	XA45937	XA35734	
Sample date	2023-05-03	2022-03-01	2021-02-19	2020-02-19	2019-03-19	
Sample temp	28	30	21	22	33	°C
Hydrogen (H2)	202*^!	0	0	3	0	µL/L
Methane (CH4)	992.0*^^!	1.0	2.0	2.0	9.0	µL/L
Ethane (C2H6)	324.0*^^^!	2.0	8.0	18.0	35.0	µL/L
Ethylene (C2H4)	2064.0*^^^!	6.0	17.0	48.0	122.0*	µL/L
Acetylene (C2H2)	25.0*^^!	0.0	0.0	0.0	3.0*^	µL/L
Carbon Monoxide (CO)	127~	32~	94~	100~	33~	µL/L
Carbon Dioxide (CO2)	2720	2199	1404	2531	2576	µL/L
Oxygen (O2)	4216	19007*	7037	24224*	28044*	µL/L
Nitrogen (N2)	53286	47211	45118	77311	56620	µL/L
Total heat gas	3380	9	27	68	166	µL/L
TDCG	3734	41	121	171	202	µL/L
Equivalent TCG	1.412	0.042	0.141	0.089	0.049	%
Total partial press	62.9	63.7	56.4	103.5	78.7	% atm
Est. safe handling limit	4.3	11.6	11.7	9.7	6.2	%
Predicted composite fault gas	258	6	17	22	8	µL/L
Acetylene/Hydrogen (C2H2/H2)	0.1			0.0		
Ethylene/Acetylene (C2H4/C2H2)	82.6				40.7	
CO2/CO	21.417	68.719	14.936	25.310	78.061	
CO/CO2	0.047	0.015	0.067	0.040	0.013	
Oxygen/Nitrogen (O2/N2)	0.079	0.403	0.156	0.313	0.495	
ETCG/ESHL	0.329	0.004	0.012	0.009	0.008	
NEI-HC	14.70	0.04	0.12	0.31	0.78	kJ/kL
NEI-CO	4.24	3.11	2.32	3.86	3.62	kJ/kL
DGA retest days	7	365	365	365	30	days
DGA retest date	2023-05-10	2023-03-01	2022-02-19	2021-02-18	2019-04-18	
DGA reference days	428.0	375.0	366.0	337.0	391.5	days
DGA result	4	1	1	1	3	
DGA diagnosis	T3					

Symbol legend: !: sharp jump, *: abnormal level, ^: abnormal increment, ~: below min interpretation level

Dissolved Gas Analysis Remarks

Sharp jump (!). Significant increase (^). High level (*). Thermal fault (above 700°C). Consider investigative sampling.



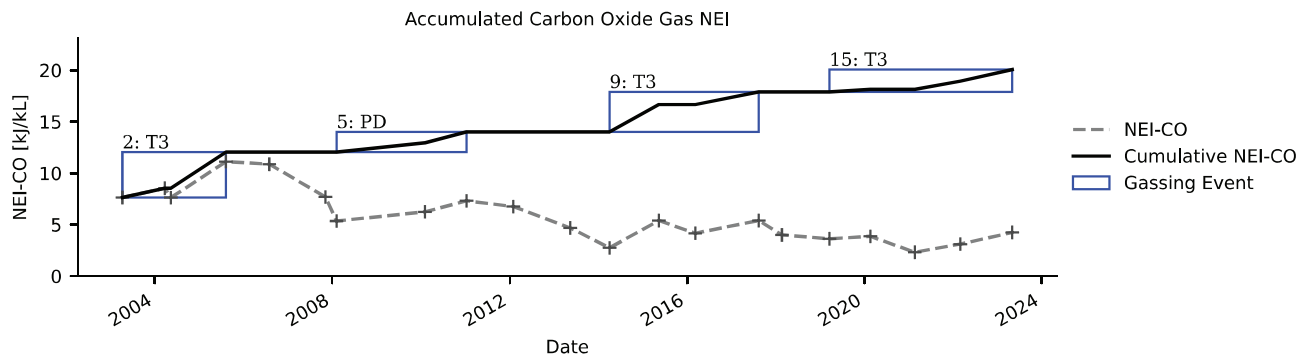
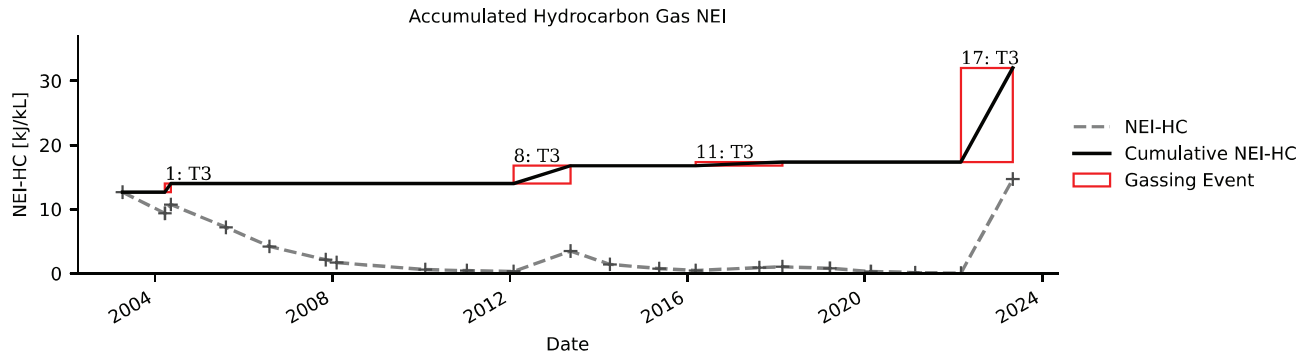
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Dissolved Gas Analysis Summary

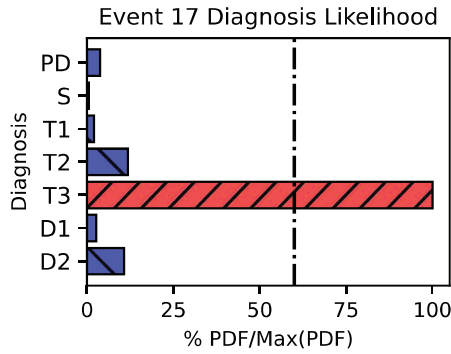
Variable name	Value	Units	Description
Methane (CH4)	992.0*^^!	μL/L	Level alert (high 121). Increment warn (121, 401, 1001). Sharp jump.
Carbon Monoxide (CO)	127~	μL/L	
Acetylene (C2H2)	25.0*^^!	μL/L	Level alert (high 3). Increment warn (3, 15, 30). Sharp jump.
Ethane (C2H6)	324.0*^^^!	μL/L	Level alert (high 66). Increment alarm (66, 101, 151). Sharp jump.
Ethylene (C2H4)	2064.0*^^^!	μL/L	Level alert (high 51). Increment alarm (51, 101, 201). Sharp jump.
Hydrogen (H2)	202*^!	μL/L	Level alert (high 101). Increment alert (101, 701, 1801). Sharp jump.

ch4*^^! co~ c2h2*^^! c2h6*^^^! c2h4*^^^! h2*^!

Gassing Events



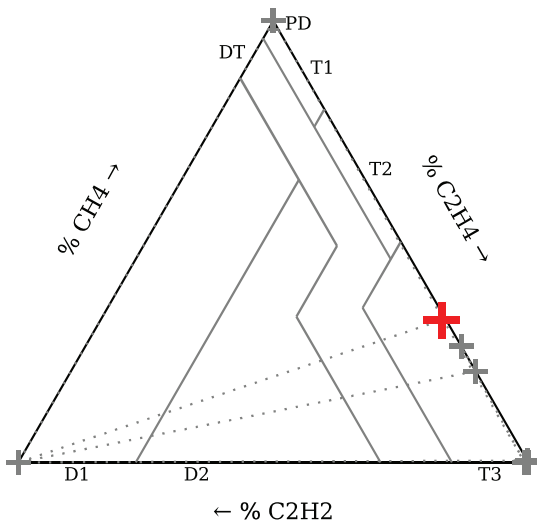
4-Simplex Diagnosis



4-Simplex Remarks

High temperature thermal fault from a hotspot inside the transformer (T > 700°C). More details can be found in the [fault type report](#).

Duval Triangle Diagnosis



Triangle Diagnosis: T3
High-range thermal fault (above 700°C).

Duval Triangle fault type determined using gas increments from NEI-based gassing events.

Moisture Analysis

Lab report number	XA78821	XA66804	XA56621	XA45937	XA35734
Sample date	2023-05-03	2022-03-01	2021-02-19	2020-02-19	2019-03-19
Sample temp	28	30	21	22	33 °C
Moisture (H2O)	15	7	27	44*	13 mg/kg
Relative saturation	19	8	47**	73***	14 %
Dew point	-7	-21	5	15	-10 °C
Moisture result	1	1	3	4	1
Moisture diagnosis			HUMID-OIL	WET-OIL	



Symbol legend: *: abnormal level

Moisture Remarks

The water content of the oil is acceptable.

Fluid Quality

Lab report number	XA78823	XA78822	XA35736	XA35735	AJ43853	
Sample date	2023-05-03	2023-05-03	2019-03-19	2019-03-19	2015-05-15	
Sample temp	28	28	32	32	32	°C
Diel brk D1816 (2 mm)	16.0***		67.0			kV
Diel breakdown D877					43.0	kV
Acid number		0.046		0.060	0.043	mg KOH/g
Interfacial tension		28.6		28.2	28.5	mN/m
Specific Gravity		0.8940		0.8900	0.8930	
Color		3.0		3.0	3.0	
Oil quality index		1.6		2.1	1.5	
Fluid quality retest days		1460	1460	1460	1460	days
Fluid quality retest date		2027-05-02	2023-03-18	2023-03-18	2019-05-14	
FQ result	4	1	1	1	1	
Fluid diagnosis	CONTAMINATED					

Symbol legend: *: abnormal level

Fluid Quality Analysis Remarks

Very low breakdown kV. There may be polar contaminants or excessive moisture.

Fluid Quality Summary

Variable name	Value	Units	Description
Diel brk D1816 (2 mm)	16.0***	kV	Level alarm (low 40, 35).

d1816_2***



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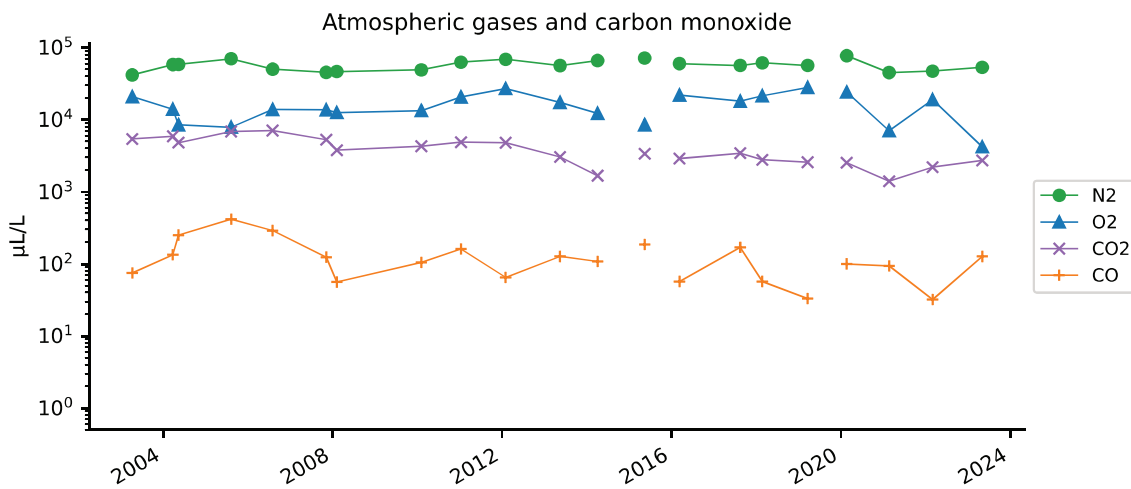
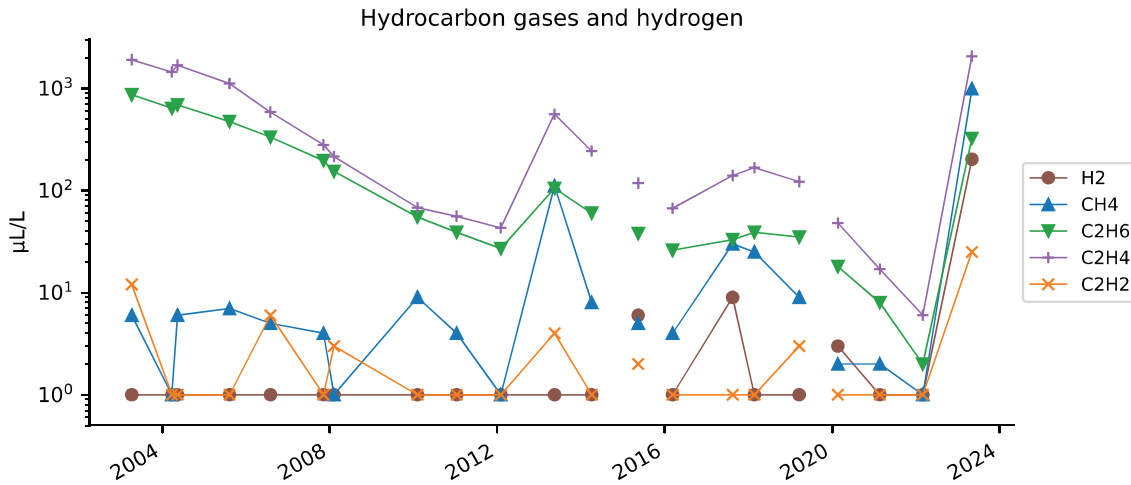
PCB Analysis

Lab report number	AA42278
Sample date	2011-01-11
Sample temp	25 °C
Aroclor 1242	41.0 mg/kg
Total PCB	41.0 mg/kg
PCB result	1

PCB Remarks

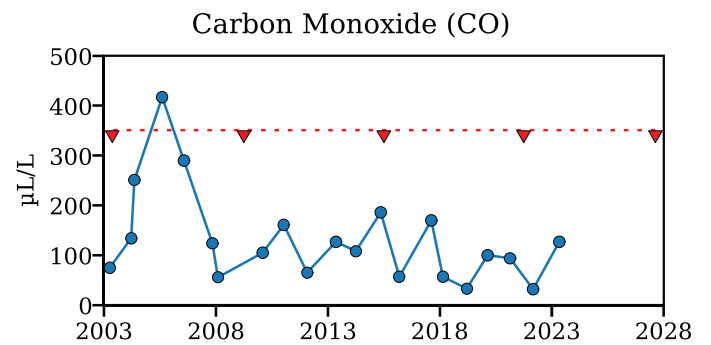
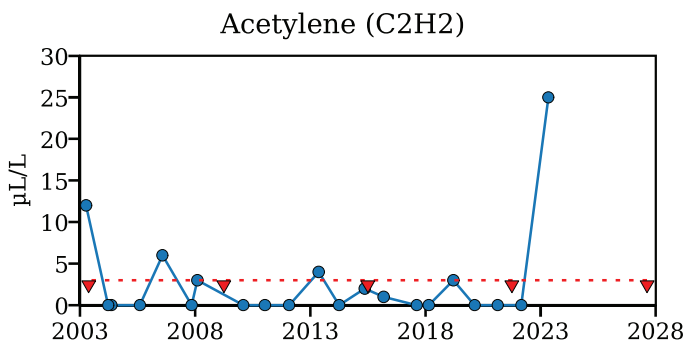
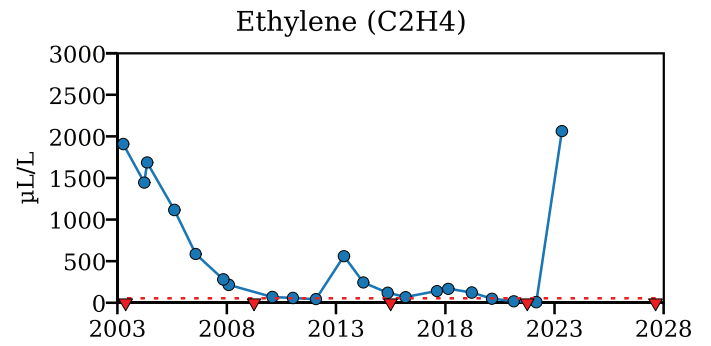
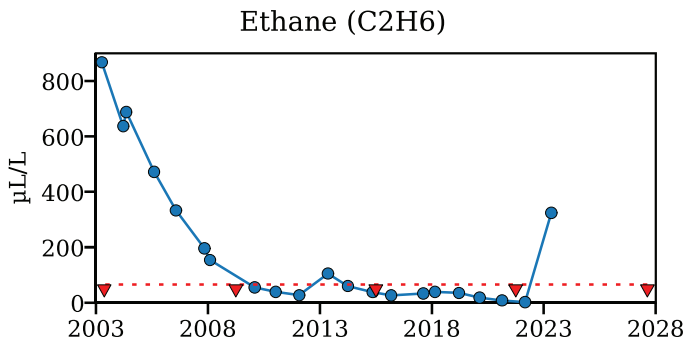
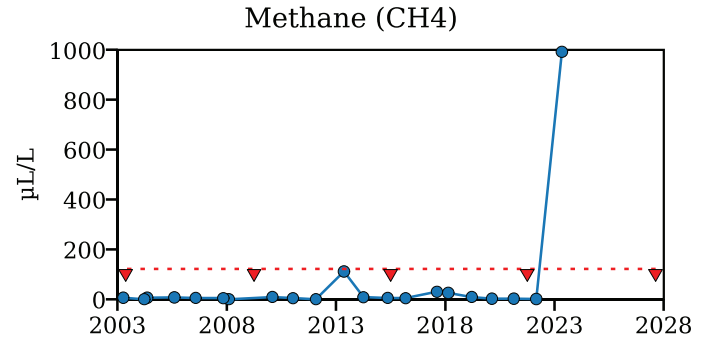
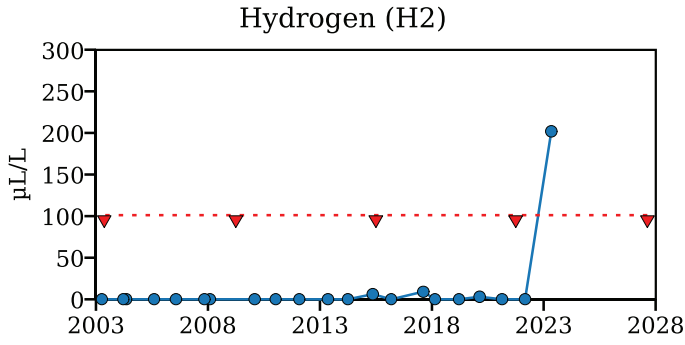
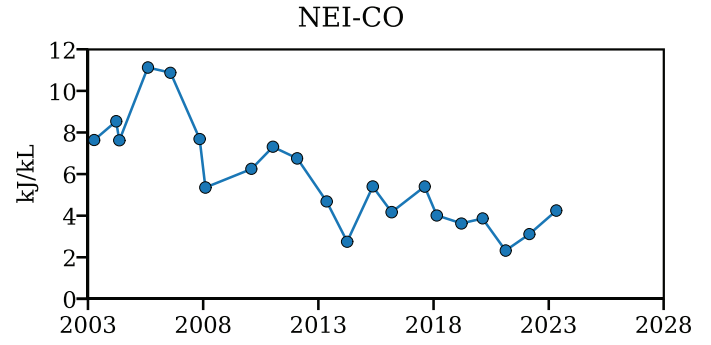
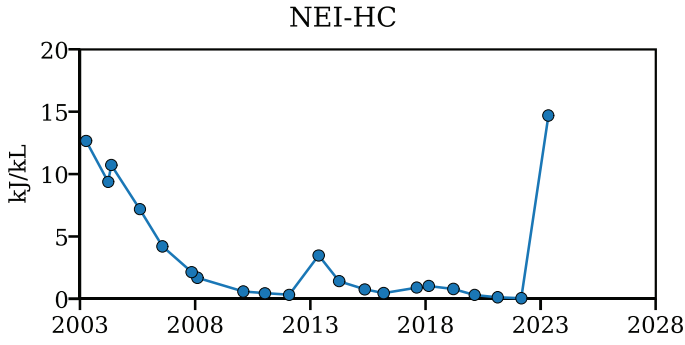
Not PCB contaminated. For a report of the last PCB sample, see the [PCB in Oil Report](#).

History Graphs and Diagnostic Charts



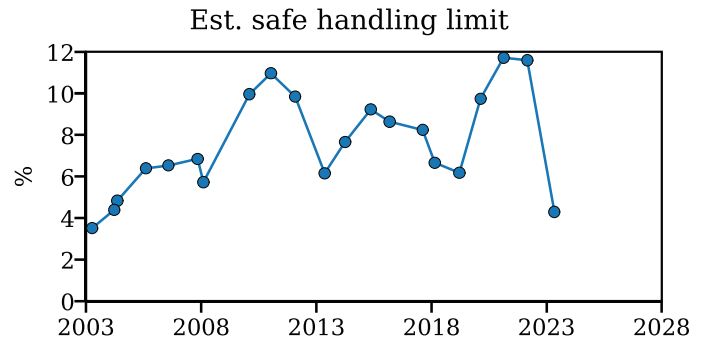
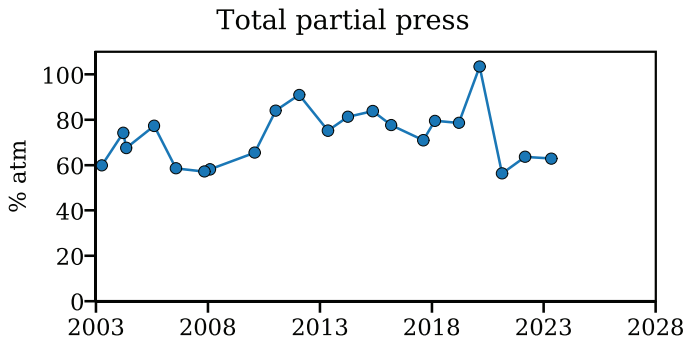
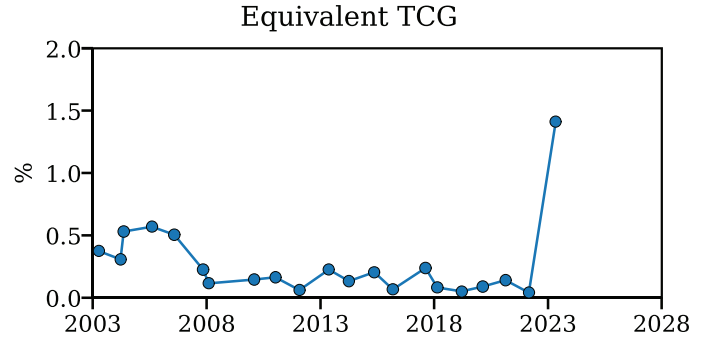
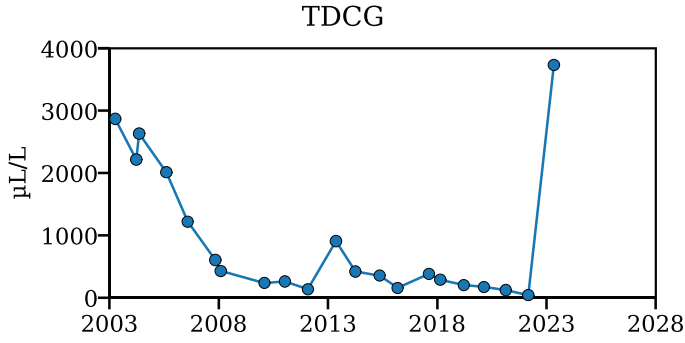
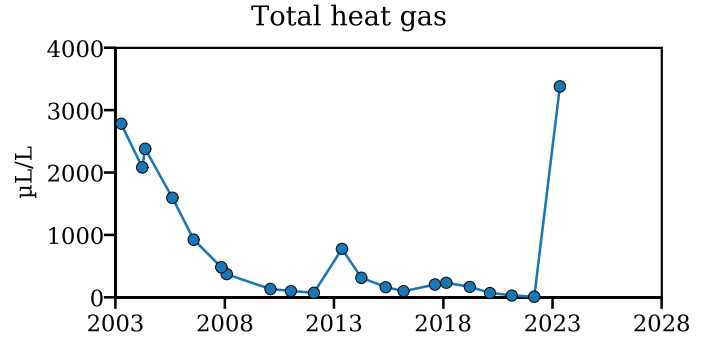
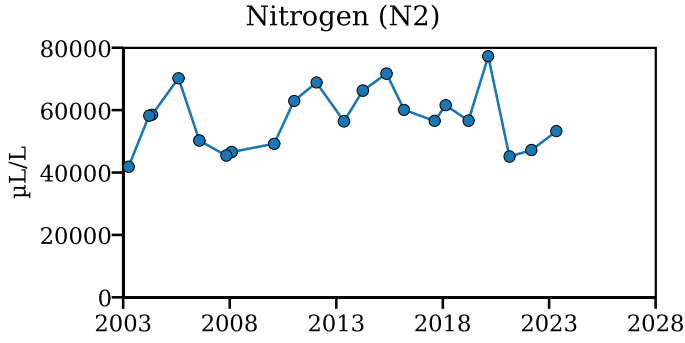
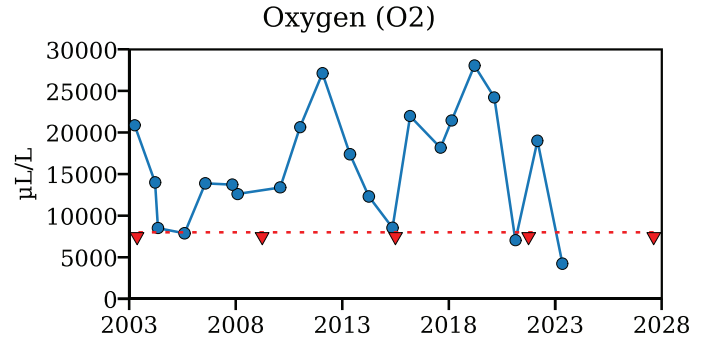
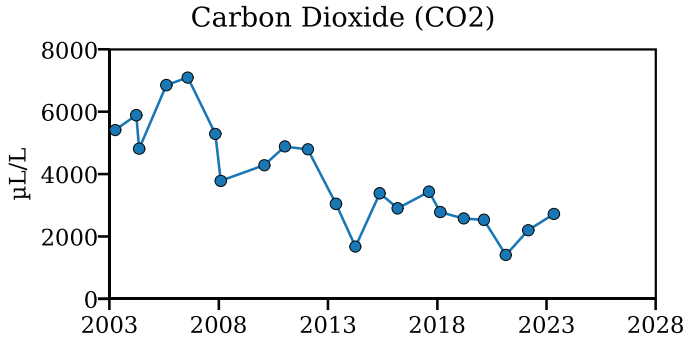


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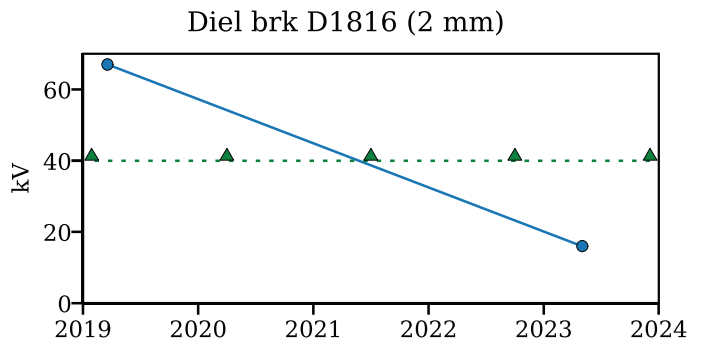
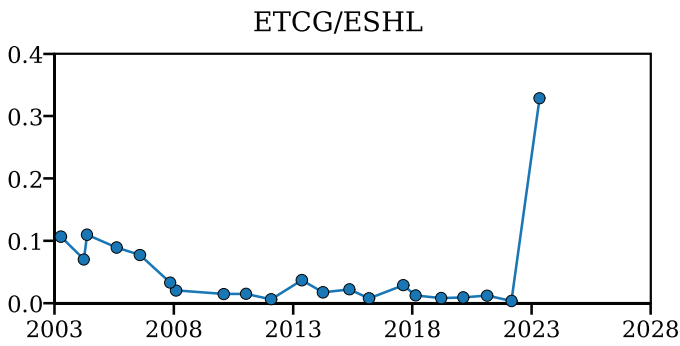
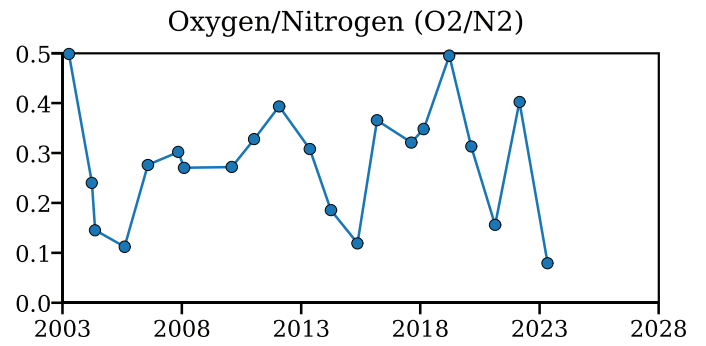
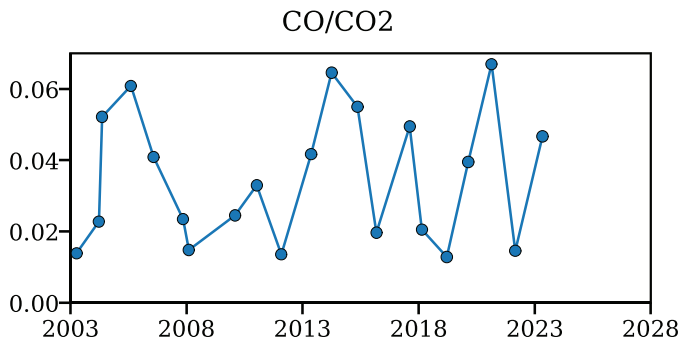
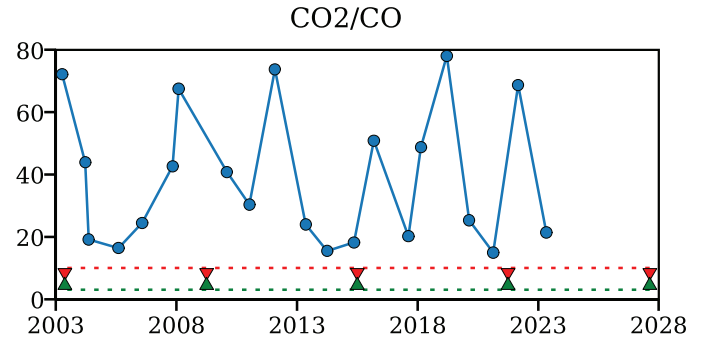
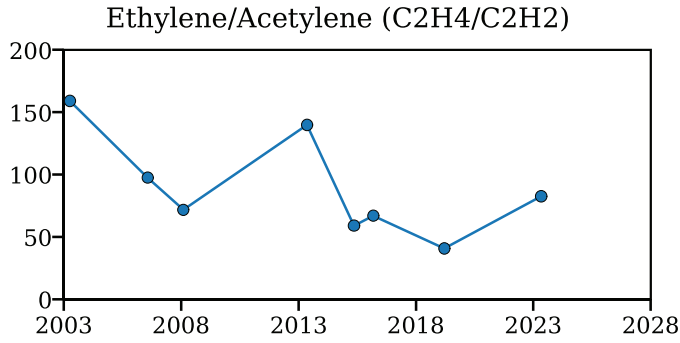
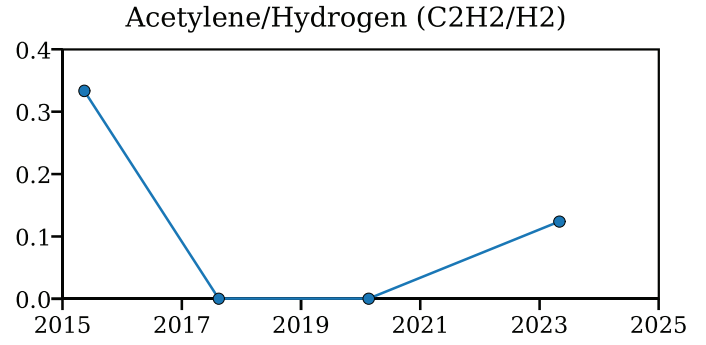
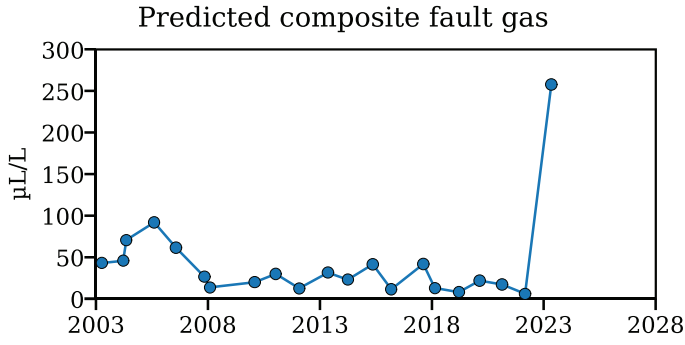


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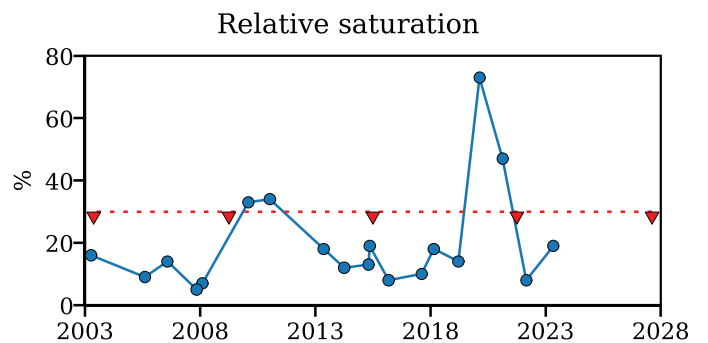
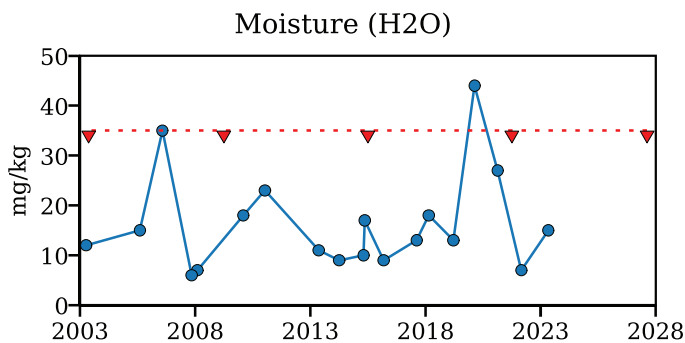
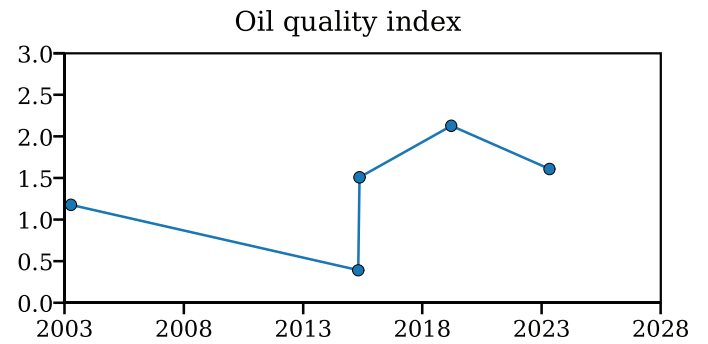
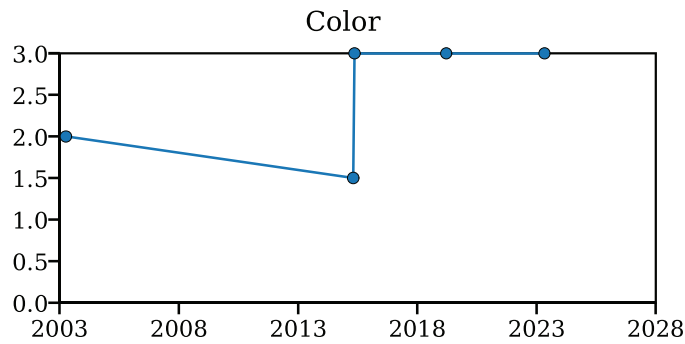
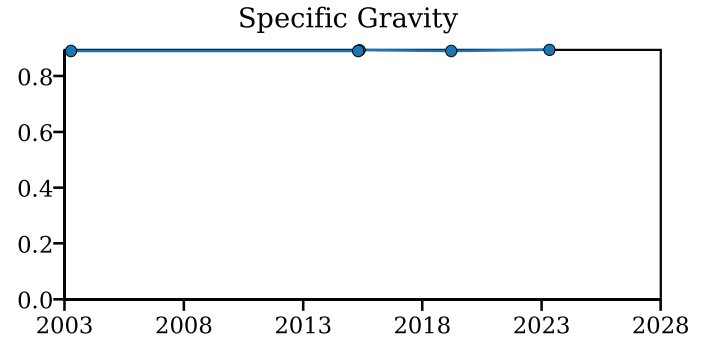
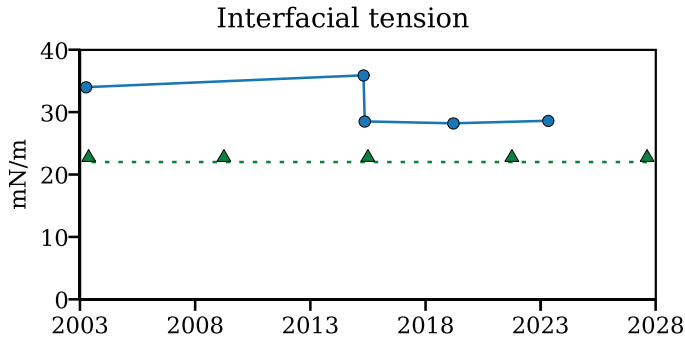
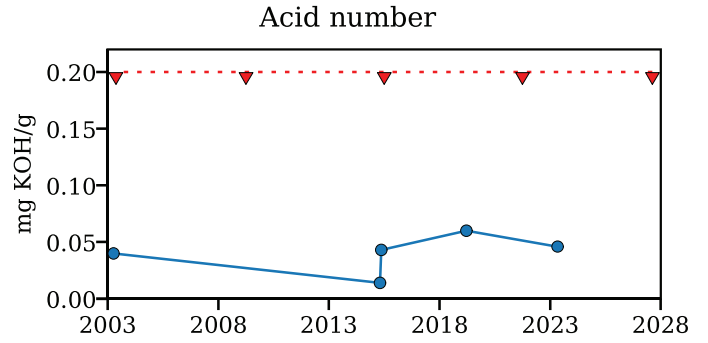
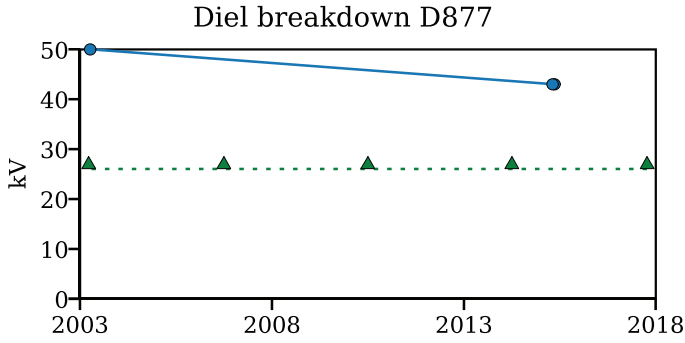


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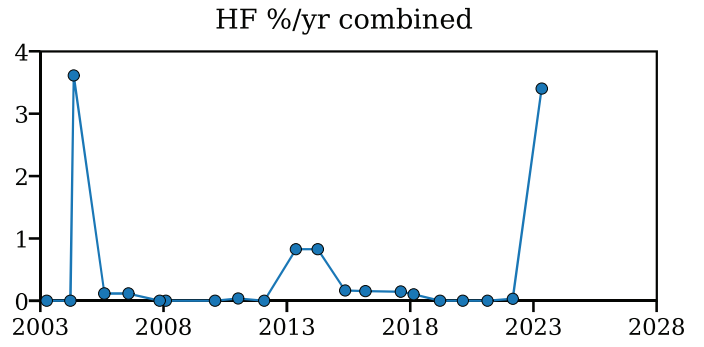
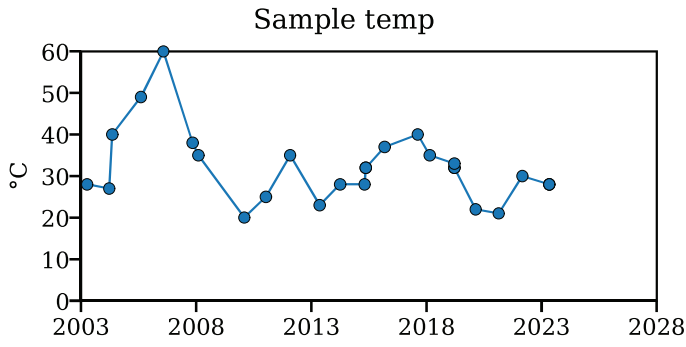


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- Raw Data
- Upper alert limit
- Lower alert limit

I&E Exhibit 5



Reliability-based DGA Quick Start Guide for TOA4 Users

1 Introduction

This Reliability-based DGA Quick Start Guide is documentation to help TOA4™ users understand and use new software features relating to **reliability-based dissolved-gas analysis (R-DGA)** for oil-filled power transformers. Reliability-based DGA is a new method of dissolved-gas analysis interpretation, developed by Delta-X Research. It is based on the trending of fault energy indices, with assessment of fault gas production in terms of failure probability and failure rate.

Fundamental Principle of Transformer DGA

A transformer is designed not to damage its internal insulation in the course of normal operation. Therefore, if insulation deterioration byproducts dissolved in the oil are increasing (beyond what is expected due to normal aging), something is wrong.

Both R-DGA and conventional DGA are methods of interpreting the same dissolved-gas data, and both are based on the Fundamental Principle of Transformer DGA displayed above. Conventional DGA, as described in the IEEE C57.104 [1] and IEC 60599 [2] guides, uses numerical limits to judge whether gas concentrations, increments, and rates of change are abnormal, and if so, how abnormal. R-DGA does not need limits; instead, it uses a statistical model of “how the gases look when the transformer is about to fail” to estimate how risky the transformer’s past gassing activity was and how risky continued gassing might be.

TOA4 provides both R-DGA and conventional DGA operating side by side. In the software’s home page, there is a link to a results comparison report showing where the two DGA methods have assessed some transformers similarly and others differently.

In the next section some basic technical concepts are discussed. The section after that provides a detailed example of how to use R-DGA in TOA4, based on the case history of a large transformer that failed unexpectedly. Finally, there is a section in which some frequently asked questions about R-DGA are answered.

2 Technical details

Reliability-based DGA builds on advancements that have been made in the last several years supporting an approach to transformer DGA that is conceptually simple, closely aligned with the Fundamental Principle of Transformer DGA, and rooted in chemistry, physics, and reliability engineering statistics.

- Base the gassing status score (1-4) on Fundamental Principle of Transformer DGA.
- Use fault energy indices to simplify trending and fault detection.
- Detect and account for gas loss from the transformer or the oil sample.
- Identify and assess gassing events (time intervals during which fault gas generation is occurring).
- Base fault type identification on gas increments during gassing events.
- Interpret the percent change in the CO/CO₂ ratio during carbon oxide gassing events.
- Use reliability statistics to relate DGA results to transformer failure.

2.1 Gassing status

A transformer's gassing status is a number between 1 and 4 defined as follows.

Conventional DGA	Code	Reliability-based DGA
Operating satisfactorily	1	No gassing ever
Greater than normal combustible gas level. Any individual gas exceeding specified levels warrants additional investigation.	2	No recent fault gas production
High level of decomposition. Any individual gas exceeding specified levels warrants additional investigation.	3	Recent fault gas production
Excessive decomposition. Continued operation could result in transformer failure.	4	Current extreme fault gas production (high Hazard Factor)

The difference between moderate and extreme fault gas production is further explained in subsection 2.6 below.

2.2 Fault energy indices

The hydrocarbon gas normalized energy intensity (NEI-HC), as the sum of heats of formation of the four low molecular weight hydrocarbon gases, weighted by fault gas concentrations, was introduced as NEI in [3] and shown to be useful for DGA trending and for assessment of fault severity. NEI-HC is defined as follows:

$$NEI-HC = \frac{77.7(CH_4) + 93.5(C_2H_6) + 104.1(C_2H_4) + 278.3(C_2H_2)}{22400} \quad (1)$$

The parenthesized gas names denote dissolved-gas concentrations ($\mu\text{L/L}$) in mineral oil, measured in the same sample and expressed at standard temperature and pressure conditions of zero degrees C and one atmosphere as specified in ASTM D3612 [4].

The numeric coefficients of the gas concentrations in the formulas are the respective standard heats of formation (kJ/mol), from n-octane (C₈H₁₈), a model for a typical mineral oil molecule for the hydrocarbon gases. The units for NEI-HC and all other forms of NEI are kJ/kL.

When there is suspicion of ethane stray gassing (significant ethane production not related to a fault), ethane is omitted from the formula above to obtain NEI-T, the "Duval triangle gas NEI."

The carbon oxide gas normalized energy intensity (NEI-CO) is defined as NEI for the carbon oxide gases CO and CO₂, with standard heats of formation from cellulose.

$$NEI-CO = \frac{101.4(CO) + 30.2(CO_2)}{22400} \quad (2)$$

NEI-CO is used for the detection and assessment of faults affecting the solid (cellulosic) insulation.

2.3 Detecting and accounting for gas loss

Unfortunately, gas loss is not a rare occurrence in DGA. When there is loss of fault gas, active fault gas production can go undetected or be underestimated. Once formed in the transformer, fault gas can escape via a leaky bushing gasket or a torn conservator diaphragm. It can escape during sampling if the oil sample is exposed to air or if the sampling syringe is leaky. Gas loss from a leaking transformer often affects several consecutive samples, whereas gas loss during sampling typically affects a single sample.

Symptoms of gas loss due to leakage or air exposure include:

- O₂/N₂ ratio greater than 0.2
- Low concentrations of hydrogen and carbon monoxide

Nitrogen-blanketed transformers can lose fault gas in a different way. When gas accumulation or high temperature raises the gas pressure in the head space, a pressure relief valve allows some of the head space gas to escape. If the temperature drops later, nitrogen is added to the head space to keep the gas pressure in the right range. The effect of occasional gas expulsion and subsequent dilution of the head space gas with nitrogen is to reduce the fault gas content of the oil, since some gas goes from the oil into the head space each time to re-establish equilibrium. If a nitrogen-blanketed transformer has a pattern of fault gas concentrations in the oil simultaneously rising and then simultaneously falling, with hydrogen and CO being strongly affected, there may be active fault gas production partially masked by gas expulsion.

Another reason for gas loss is degassing, which usually shows up in a transformer's DGA history as a simultaneous deep drop in all gases. Over several weeks following the degassing, some of the dissolved gas trapped in the windings diffuses out into the bulk oil to re-establish an equilibrium.

To mitigate the effects of gas loss on fault detection and assessment, TOA4 bases its R-DGA interpretation on a statistical estimate of gas production obtained by smoothing the gas data to reduce the "noise" inherent in sampling and laboratory analysis, then ignoring large decreases. In the NEI event graphs (Figure 6), the gray crosses represent "raw" data, while the black line represents cumulative data.

2.4 Gassing events

A gassing event in a time series graph is a time interval during which the variable is increasing. For example, in Figure 6 the numbered boxes indicate gassing events in which NEI-CO and NEI-HC increased. Other gassing events that may be noted by TOA4 are CO/CO₂ events, associated with increases in that gas ratio, and acetylene events, when the acetylene concentration is increasing.

The apparent fault type during a gassing event is determined by calculating how much methane, ethylene, and acetylene increased during the event and plotting those amounts in the Duval triangle. Those gas increments represent new fault gas produced by whatever is causing the event.

NEI-HC, NEI-T, and NEI-CO gassing events have statistical properties called severity and hazard factor that are explained in subsection 2.6 below.

2.5 CO/CO₂ ratio

The percent increase of the CO/CO₂ ratio during a gassing event, especially during an NEI-CO event, can provide an indication of the location of a fault affecting paper insulation. An increase in the CO/CO₂ ratio by 33% to 100% suggests local deterioration of paper insulation outside of the windings, such as on a hot bushing or NLTC lead. A very large increase – 185% or more – may indicate deterioration of paper insulation inside the windings or in some confined space. The meaning of an increase between those two ranges is ambiguous. A decrease in the ratio indicates that CO₂ is being produced faster than CO, which commonly is a sign that paper insulation is being stressed by general overheating.

Remarkably, the interpretation of percent increases in the CO/CO₂ ratio is valid even when gas loss is involved, i.e. even when one or both of the carbon oxide gas concentrations is decreasing. That is explained by the fact that CO is more volatile and much less soluble in oil than CO₂. Any gas loss must affect CO much worse than CO₂, so it follows that the CO/CO₂ ratio can increase only if there is active production of CO.

2.6 Statistical model

Reliability-based DGA relies upon a pre-defined statistical model, derived from a large DGA database augmented with failure data, showing how the level of each fault energy index is distributed in transformers that are not far from failure [5]. From the model, various quantities can be obtained for assessment of fault gas production. R-DGA is especially concerned with these statistical quantities related to a gassing event where a fault energy index increases from an initial value *a* to a final or most recent value *b*:

Severity. The severity of the event is the prevalence (expressed as a percentage) of transformers, actively gassing with NEI in that range, that fail. Cumulative severity is the severity of a gassing event starting from zero and increasing to *b*.

Hazard factor (HF). The hazard factor at the upper end *b* of the event is the failure rate (percent failures per additional NEI unit of gassing) for NEI = *b*, times the NEI rate of increase (NEI units per year) at that point. HF can be understood as an estimate – in percentage points per year – of how fast the severity is increasing as of the latest sample in the event.

In TOA4, to qualify as "extreme" a gassing event must have high enough severity to not be just a "blip," and its hazard factor has to exceed the 90th percentile value of HF in a large number of gassing events observed in our research database.

3 Example

The following detailed example shows how to look at and understand Reliability-based DGA results in TOA4. Here R-DGA reveals a serious transformer problem that was overlooked by conventional DGA. The transformer is a 230 kV, 250 MVA nitrogen-blanketed unit manufactured in 1982.

3.1 Equipment list – R-DGA status

Equip Num	S/N	Apprtype	Substation	Desig	Last DGA sample	DGA	Gassing	HF %	Sev %	FT	Event	RCOR %
** EXAMPLE-TL12	EXAMPLE-TL12	TRN	EXAMPLE	TL12	2010-08-18	0.13	3	0.70	0.70	T1	CO	

Figure 1: TOA4 Online Equipment List with example transformer shown.

The TOA4 Equipment List has a new "Columns" selection, "R-DGA status," that adds some additional information to that displayed in the "DGA status" and "Review new data" views of the equipment list.

This item in the equipment list has a gassing status of 3 (recent fault gas production), even though the conventional DGA result is 1/1, i.e. 1 (unexceptional) previously and still 1 as of the latest sample – no conventional DGA limits have been exceeded.

The recent gassing is in the form of an upward trend in NEI-CO, the carbon oxide gas fault energy index. The severity (Sev%) is 0.70%, meaning that 7 out of 1000 transformers (on average) would fail during similar gassing. The hazard factor (HF%) of 0.13 percentage points per year means that continued gassing will add about 1.3 per thousand transformers to the severity per year. The apparent fault type is T1, overheating below 300 degrees Celsius. Does this seem like it should be ignored? Perhaps not. To open the R-DGA report, you could click the “3” under “Gassing.”

3.2 R-DGA report - diagnostic overview

Read the “Reliability-based DGA diagnosis” text (Figure 2) to get the bottom-line conclusion of the report. In this example, it is short and undramatic. Apparently, some paper insulation is being cooked.

Reliability-based DGA Diagnosis

Recent fault gas production (gassing status 3). Recent carbon oxide gas production suggests thermal stressing of paper insulation.

Figure 2: Diagnostic remarks in R-DGA report.

The RDGA summary just below the diagnostic text in the report provides a compact overview of the results, the most important of which we have already seen in the equipment list. See Figure 3.

Reliability-based DGA Summary

DGA last date	2010-08-18	Event Summary	nei_co+
DGA samples	27	Cumulative sev liquid %	0.00
Gassing events	6	Cumulative sev paper %	1.11
Event fault type	N/A	Gassing status	3
Hazard factor %	0.18		

Figure 3: Summary of results in R-DGA report.

We have DGA data for this transformer starting in May 1994. From then until August 2010, the DGA results seem pretty unexceptional by conventional standards, not budging above IEEE status code 1. As Figure 4 shows, the CO₂ concentration bounced around a bit, averaging about 4000 μL/L, while CO remained low but also varied. There were three occasions when hydrogen, methane, or ethane had a large increment, although no limits were exceeded. Figure 5 shows that hydrogen and the hydrocarbon gases stayed low but varied quite a bit.

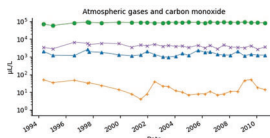


Figure 4: Chart of atmospheric and carbon oxide gases.

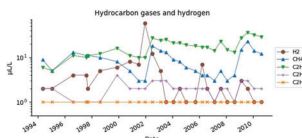


Figure 5: Chart of hydrogen and hydrocarbon gases.

The gassing event charts for NEI-HC and NEI-CO (see Figure 6) are usually the most important and informative part of the R-DGA report, and in this example they illustrate the usefulness of using cumulative fault energy indexes for DGA trending. The gray crosses represent the NEI values calculated from raw data, while the black line is the result of smoothing and accumulation. For both NEI-HC and NEI-CO, the cumulative graphs reveal that gas loss has been concealing long-term upward trends, i.e., fault gas production.

Gassing Events

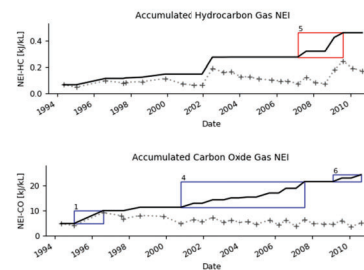


Figure 6: Fault energy index charts with gassing events indicated by colored boxes.

According to the dissolved-gas data shown in the report, the O₂/N₂ ratio is consistently well below 0.1, suggesting that there is no gas leak or sampling problem. The transformer is nitrogen-blanketed, so evidently gas loss in this case is due to pressure relief head space gas expulsion.

In both NEI gassing event graphs, colored boxes mark gassing events – episodes where an upward trend results in a significant increase in NEI-CO or NEI-HC. In general, some gassing events may coincide with overloading, and in other cases the onset of a gassing event may coincide with a traumatic incident such as a through fault. In this example no information is available to identify possible external reasons for fault gas production.

Figure 7 is the events table from the report. Numbers in the ID column of the table correspond to the numbers above the gassing event boxes on the graphs. Event types CO and HC correspond to boxes in the NEI-CO and the NEI-HC graphs, respectively. Event type R corresponds to event boxes in the graph of the CO/CO₂ ratio, not shown because for this example those events are not very interesting.

ID	Event	Event start	Start value	Inc	Days	Samples	FT	RCOR %	Sev %	HF %
1	CO	1995-01-16	4.795	5.142	576	2	S		0.11	0.11
2	R	2001-07-02	0.005	0.002	374	3	O	45		
3	R	2003-07-10	0.006	0.002	545	4		35		
4	CO	2000-10-27	11.286	10.200	2474	14	O		0.68	0.11
5	HC	2007-02-21	0.275	0.186	897	6	O		0.08	0.03
6	CO	2009-02-11	21.487	2.757	553	4			0.26	0.18

Figure 7: Table describing gassing events.

Event fault types are indicated in column FT. Fault type S is said to represent stray gassing, but in our experience it more often seems to indicate T1. Fault type O designates a thermal fault that can be regarded as a mild T1 – temperatures below 250 degrees C instead of 300 degrees C. The S and O fault types belong to a supplementary Duval triangle for low-energy thermal faults (not shown). In the classic Duval triangle (Figure 8), each cross represents a gassing event, with the red one being the most recent, event 6. The indicated fault type for all the events is T1.

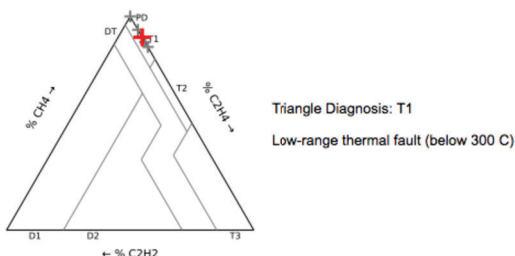


Figure 8: Duval triangle with one point plotted for each event having a fault type.

The probability density graphs (Figure 9) near the top of the R-DGA report can now be explained. The curves are the probability density curves for the distributions of NEI-HC and NEI-CO just before transformer failure. Annotations to the curves compare the example transformer's gassing to the statistical model. The gray area indicated under each curve represents cumulative severity of the transformer's gassing, and the red arrow pointing to the right represents the hazard factor

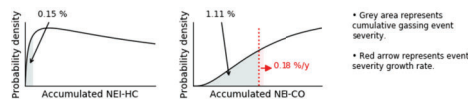


Figure 9: Probability density graphs comparing the example transformer's gassing to the statistical model.

The NEI-CO cumulative severity of 1.11% means that (according to the model) on average 11.1 out of 1000 transformers would fail before reaching the NEI-CO level of the example transformer. The NEI-CO hazard factor of 0.18 percentage points per year indicates that about 1.8 additional ones out of 1000 transformers gassing similarly to the example transformer would fail per year. While such numbers do not suggest an emergency, they do indicate the existence of a problem that poses an increasing risk of failure and therefore should not be ignored. While this large transformer continues to cook its insulation paper, the dice are being rolled.

This transformer failed seven months after the last sample shown here with turn-to-turn arcing. The post-mortem inspection revealed extensive charring of winding insulation paper and clamping plate pressboard.



4 Questions

4.1 What should be done for “under the radar” cases?

In cases such as the example presented in Section 3, where Reliability-based DGA classifies a transformer as abnormal because of recent fault gas production that has low severity and HF, especially if conventional DGA does not identify the transformer as abnormal, what is the appropriate follow-up? Neither Delta-X Research nor its software TOA4 provides direct advice on transformer operation and maintenance, but in answer to this question we can point out some reasonable generalities.

- Each case must be evaluated on the basis of all available relevant information, not just DGA.
- Any active fault gas production is, by the Fundamental Principle of Transformer DGA, abnormal and undesirable and, according to our statistical analysis, risky. Understanding the origin and cause of the gassing (say, by electrical testing and IR scanning) may help to quantify the risk beyond what R-DGA is able to do.
- If the indicated problem (such as chronic T1 heating) cannot in some way be mitigated or eliminated as a concern, increased DGA sampling frequency or online monitoring (with either a hydrogen or a multi-gas monitor) could help to manage the risk of the problem worsening.

4.2 Does the R-DGA statistical model have to be recalculated for my transformers?

No. Derivation of the model requires a very large database of transformer DGA and failure data. The current R-DGA statistical model is based on DGA histories and failure data from significant transformer populations provided by some of our customers. It is not subdivided with regard to transformer size, age, loading, or other properties, so it represents “power transformers in general”. This model performed extremely well when it was used to assess DGA data for transformers of a major electric utility that did not contribute to the initial research data set. When we have collected sufficient additional data, we will investigate whether separate statistical models are useful for specific transformer types and sizes.

4.3 Does R-DGA replace the Duval triangle?

No. R-DGA is not a method for fault type identification. It is all about:

- Determining whether the transformer is or has been producing fault gas; and
- If so, providing a numerical estimate of the associated risk.

In TOA4, both conventional DGA and R-DGA use the Duval triangle, if there is evidence

of fault gas production, to determine what kind of fault seems to be producing the gas.

4.4 Does R-DGA work for transformers with alternative insulating liquids? LTCs?

For now we are providing R-DGA only for transformers filled with mineral oil. Because the “classic” Duval triangle based on methane, ethylene, and acetylene required only minor alterations for application to transformers using ester and silicone insulating liquids, it appears that those gases play approximately the same role for esters and silicone as for mineral oil, in which case R-DGA based on NEI-T (methane, ethylene, and acetylene) should work pretty well for those alternative liquids. To apply R-DGA fully to each of the alternative liquids, however, a large amount of DGA and failure data must be collected, and then more research will be needed.

It is known that gassing behavior can differ greatly between LTC models and even between populations of the same model due to differences in operating frequency, loading, and maintenance practices. These and other complications make it very impractical to apply the statistical method of R-DGA to LTCs, although some other elements of R-DGA, such as the use of energy indexes, may turn out to be useful.

References

- [1] “IEEE guide for the interpretation of gases generated in oil-immersed transformers,” *IEEE Std C57.104-2008 (Revision of IEEE Std C57.104-1991)*, pp. 1–36, Feb 2009.
- [2] *Mineral oil-filled electrical equipment in service – Guidance on the interpretation of dissolved and free gases analysis*, 3rd ed. International Electrotechnical Commission, Sep 2015, no. IEC 60599-2015-09.
- [3] F. Jakob and J. J. Dukarm, “Thermodynamic estimation of transformer fault severity,” *IEEE Transactions on Power Delivery*, vol. 30, no. 4, pp. 1941–1948, Aug 2015.
- [4] ASTM, *Standard Test Method for Analysis of Gases Dissolved in Electrical Insulating Oil by Gas Chromatography*. ASTM International, 2017, no. ASTM D3612-02(2017).
- [5] J. J. Dukarm and M. Duval, “Transformer reliability and dissolved-gas analysis,” in *2016 CIGRE Canada Conference*, no. CIGRE-807, Vancouver BC, Oct 2016.

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I&E Exhibit 6

Equipment	PNS000500001042	Spare	False
Serial No.	SDV301704	Tank	BOT MAIN
Apparatus type	TRN	Norms used	TRN_IEEE_INC_69KV
Equipment group name	Transmission	DGA result	4→4
Owner	3000 - Penelec	Moisture result	1↗3
Region	305 - Warren	FQ result	1↗4
Substation	PNS-DEL EQU WARREN	Trace elements result	0→0
Norms	TRN_IEEE_INC_69KV	Particle analysis result	0→0
Description	1 BK 34-12 KV (NON TYPE U BUSHINGS)	PCB result	0↗1
Manufacturer	Westinghouse Electric	Furan result	0→0
Model	Unknown	Oil test status	UNREVIEWED
In service	True		

This transformer has a Reliability-based dissolved gas analysis report available. That report gives deeper insight into the status of the transformer by analyzing the entire DGA history and by comparing it with statistical models of similar transformers. Click [here](#) for more details on the method and [here](#) to view the report for this transformer.

Last Analysis Done On 2023-08-30

Last sample date	2023-08-28
Equipment last modified date	2024-08-02
Norms last modified date	2000-01-01
Last analysis date	2023-08-30
Read-only samples	0
Excluded samples	0
Total samples	28

Sample Remarks

Sampled	Container	Reviewer remarks
2023-08-28 12:00:00	DGA0007144	Failed Transformer - TX Out of Service - Bad TTR Results - Report to Dave Thomas
2023-05-03 12:06:00	BETA000070689	DGA analyzed twice to confirm increase in gas.
2023-05-03 12:05:00	BETA000070687	DGA analyzed twice to confirm increase in gas.
2023-05-03 12:01:00	DGA0014851	DGA analyzed twice to confirm increase in gas.
2022-03-01 12:01:00	DGA0007744	.

Dissolved Gas Analysis

Lab report number	AL36223	XA78821	XA66804	XA56621	XA45937	
Sample date	2023-08-28	2023-05-03	2022-03-01	2021-02-19	2020-02-19	
Sample temp	25	28	30	21	22	°C
Hydrogen (H2)	3966*^^^!	202*^!	0	0	3	µL/L
Methane (CH4)	2245.0*^^^!	992.0*^^^!	1.0	2.0	2.0	µL/L
Ethane (C2H6)	599.0*^^^!	324.0*^^^!	2.0	8.0	18.0	µL/L
Ethylene (C2H4)	5737.0*^^^!	2064.0*^^^!	6.0	17.0	48.0	µL/L
Acetylene (C2H2)	10550.0*^^^!	25.0*^^^!	0.0	0.0	0.0	µL/L
Carbon Monoxide (CO)	179~	127~	32~	94~	100~	µL/L
Carbon Dioxide (CO2)	3097	2720	2199	1404	2531	µL/L
Oxygen (O2)	17480*	4216	19007*	7037	24224*	µL/L
Nitrogen (N2)	45070	53286	47211	45118	77311	µL/L
Total heat gas	8581	3380	9	27	68	µL/L
TDCG	23276	3734	41	121	171	µL/L
Equivalent TCG	13.680	1.412	0.042	0.141	0.089	%
Total partial press	71.5	62.9	63.7	56.4	103.5	% atm
Est. safe handling limit	3.8	4.3	11.6	11.7	9.7	%
Predicted composite fault gas	4928	258	6	17	22	µL/L
Acetylene/Hydrogen (C2H2/H2)	2.7	0.1			0.0	
Ethylene/Acetylene (C2H4/C2H2)	0.5	82.6				
CO2/CO	17.302	21.417	68.719	14.936	25.310	
CO/CO2	0.058	0.047	0.015	0.067	0.040	
Oxygen/Nitrogen (O2/N2)	0.388	0.079	0.403	0.156	0.313	
ETCG/ESHL	3.599	0.329	0.004	0.012	0.009	
NEI-HC	168.02	14.70	0.04	0.12	0.31	kJ/kL
NEI-CO	4.98	4.24	3.11	2.32	3.86	kJ/kL
DGA retest days	7	7	365	365	365	days
DGA retest date	2023-09-04	2023-05-10	2023-03-01	2022-02-19	2021-02-18	
DGA reference days	117.0	428.0	375.0	366.0	337.0	days
DGA result	4	4	1	1	1	
DGA diagnosis	D2	T3				

Symbol legend: !: sharp jump, *: abnormal level, ^: abnormal increment, ~: below min interpretation level

Dissolved Gas Analysis Remarks

The high O2/N2 ratio suggests that the equipment item may be exchanging fault gases with the atmosphere or the sample was mishandled. If that is so, fault severity may be underestimated and fault type may be inaccurate. The high C2H2/H2 ratio suggests contamination from OLTC. This can be confirmed by comparing DGA results in the main tank with those in the OLTC and/or conservator. Sharp jump

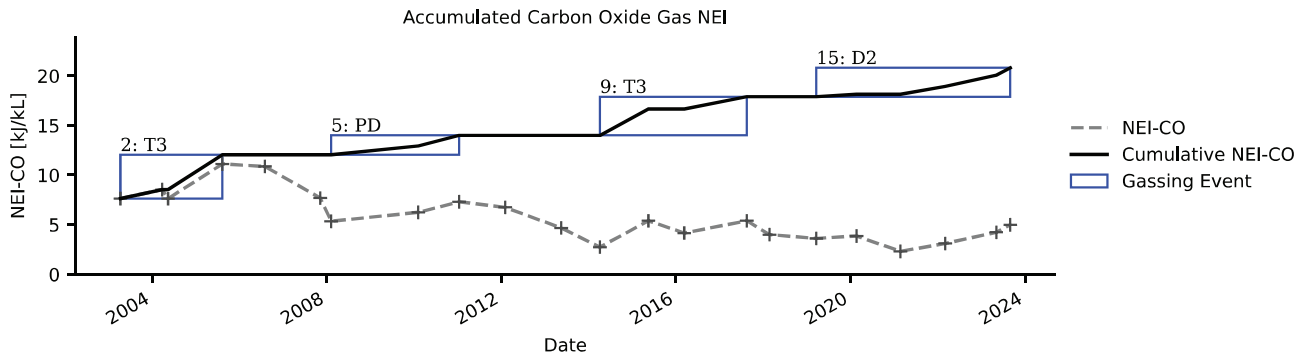
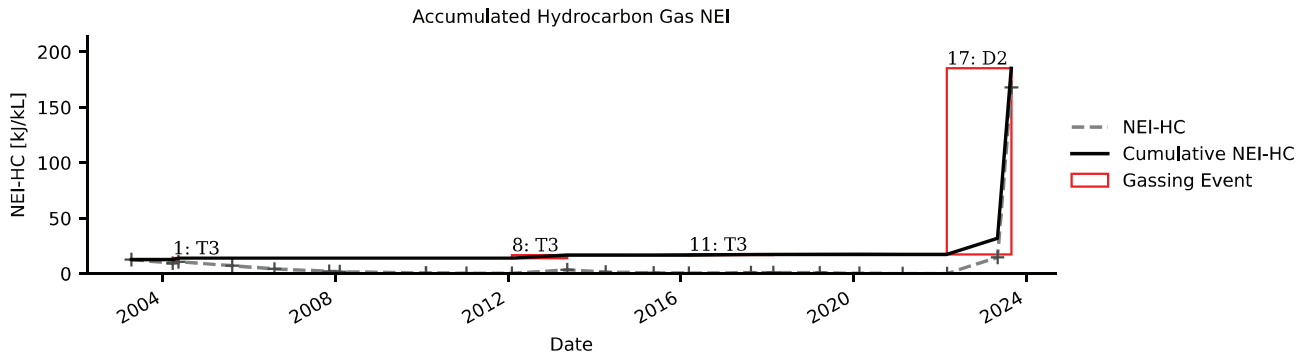
(!). Significant increase (^). High level (*). High-energy arcing. Consider investigative sampling. Estimated combustible gas in the headspace exceeds the estimated safe handling limit (based on the ETCG/ESHL ratio).

Dissolved Gas Analysis Summary

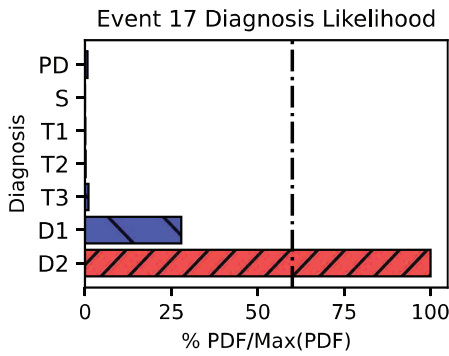
Variable name	Value	Units	Description
Hydrogen (H2)	3966*^^^!	µL/L	Level alert (high 101). Increment alarm (101, 701, 1801). Sharp jump.
Carbon Monoxide (CO)	179~	µL/L	
Ethane (C2H6)	599.0*^^^!	µL/L	Level alert (high 66). Increment alarm (66, 101, 151). Sharp jump.
Oxygen (O2)	17480*	µL/L	Level alert (high 8000).
Ethylene (C2H4)	5737.0*^^^!	µL/L	Level alert (high 51). Increment alarm (51, 101, 201). Sharp jump.
Acetylene (C2H2)	10550.0*^^^!	µL/L	Level alert (high 3). Increment alarm (3, 15, 30). Sharp jump.
Methane (CH4)	2245.0*^^^!	µL/L	Level alert (high 121). Increment alarm (121, 401, 1001). Sharp jump.

h2*^^^! co~ c2h6*^^^! o2* c2h4*^^^! c2h2*^^^! ch4*^^^!

Gassing Events



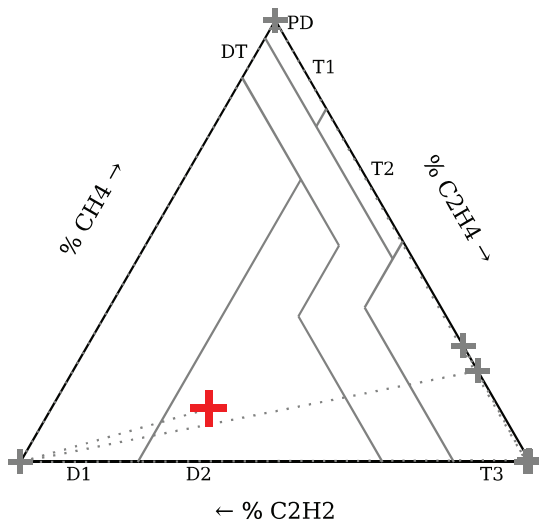
4-Simplex Diagnosis



4-Simplex Remarks

High energy discharge from long duration electrical arcing between conductors. Sustained arc. Likely has a hotspot associated with it. More details can be found in the [fault type report](#).

Duval Triangle Diagnosis



Triangle Diagnosis: D2
High energy arcing discharge.

Duval Triangle fault type determined using gas increments from NEI-based gassing events.

Moisture Analysis

Lab report number	AL36223	XA78821	XA66804	XA56621	XA45937	
Sample date	2023-08-28	2023-05-03	2022-03-01	2021-02-19	2020-02-19	
Sample temp	25	28	30	21	22	°C
Moisture (H2O)	30	15	7	27	44*	mg/kg
Relative saturation	44**	19	8	47**	73***	%
Dew point	7	-7	-21	5	15	°C
Moisture result	3	1	1	3	4	
Moisture diagnosis	HUMID-OIL		HUMID-OIL		WET-OIL	

Symbol legend: *: abnormal level

Moisture Remarks

The relative saturation of water in the oil is high. This may be explained by a recent temperature drop or by moist cellulose; or (if calculated) it may be overestimated due to increased water solubility in aged oil. Consider resampling to verify this result. If the condition persists, investigate the moisture source.

Moisture Summary

Variable name	Value	Units	Description
Relative saturation	44**	%	Level warn (high 30, 40, 50).

relsaturation**

Fluid Quality

Lab report number	XA78823	XA78822	XA35736	XA35735	AJ43853	
Sample date	2023-05-03	2023-05-03	2019-03-19	2019-03-19	2015-05-15	
Sample temp	28	28	32	32	32	°C
Diel brk D1816 (2 mm)	16.0***		67.0			kV
Diel breakdown D877					43.0	kV
Acid number	0.046		0.060		0.043	mg KOH/g
Interfacial tension	28.6		28.2		28.5	mN/m
Specific Gravity	0.8940		0.8900		0.8930	
Color	3.0		3.0		3.0	
Oil quality index	1.6		2.1		1.5	
Fluid quality retest days	1460		1460		1460	days
Fluid quality retest date	2027-05-02		2023-03-18		2019-05-14	
FQ result	4	1	1	1	1	
Fluid diagnosis	CONTAMINATED					

Symbol legend: *: abnormal level

Fluid Quality Analysis Remarks

Very low breakdown kV. There may be polar contaminants or excessive moisture.

Fluid Quality Summary

Variable name	Value	Units	Description
Diel brk D1816 (2 mm)	16.0***	kV	Level alarm (low 40, 35).

d1816_2***

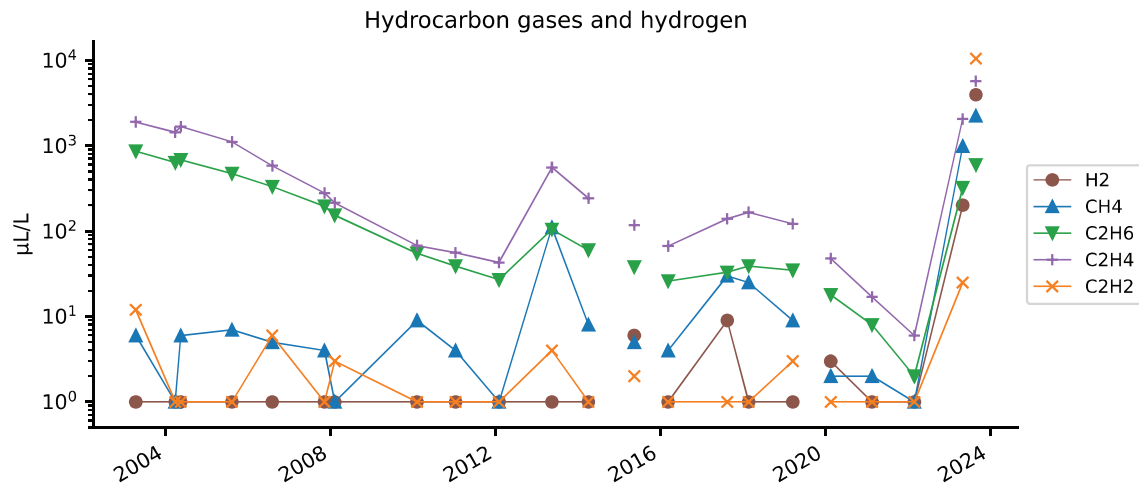
PCB Analysis

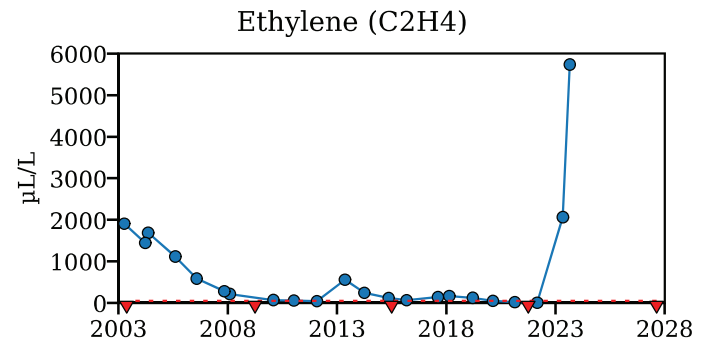
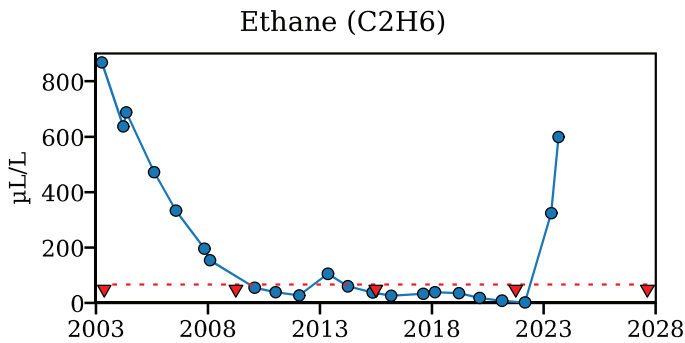
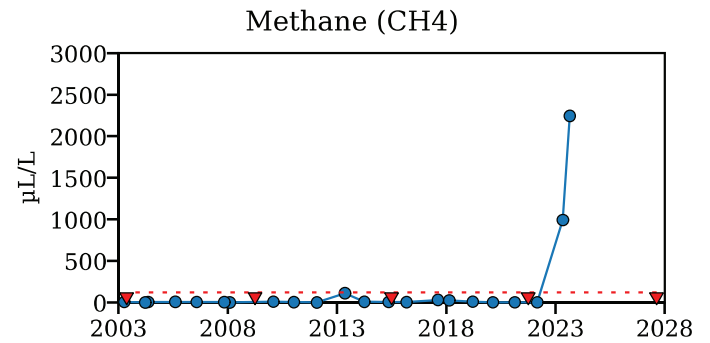
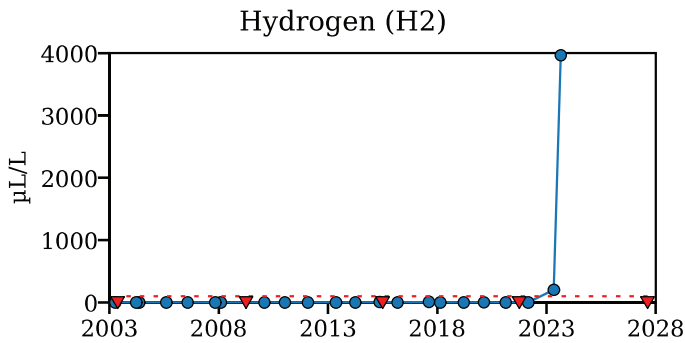
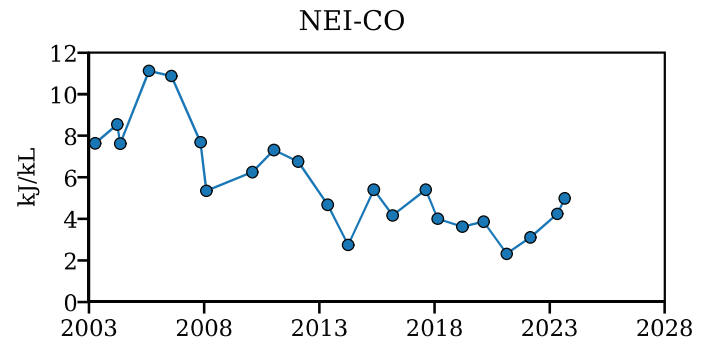
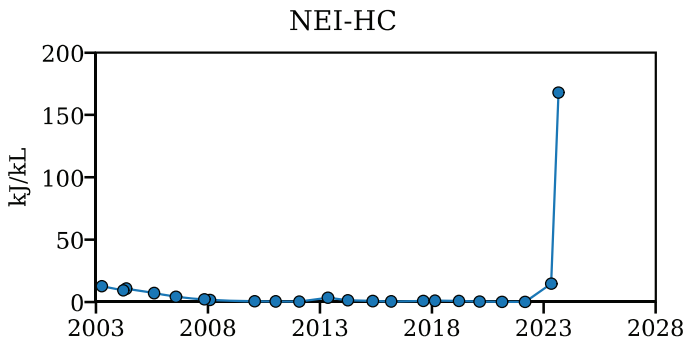
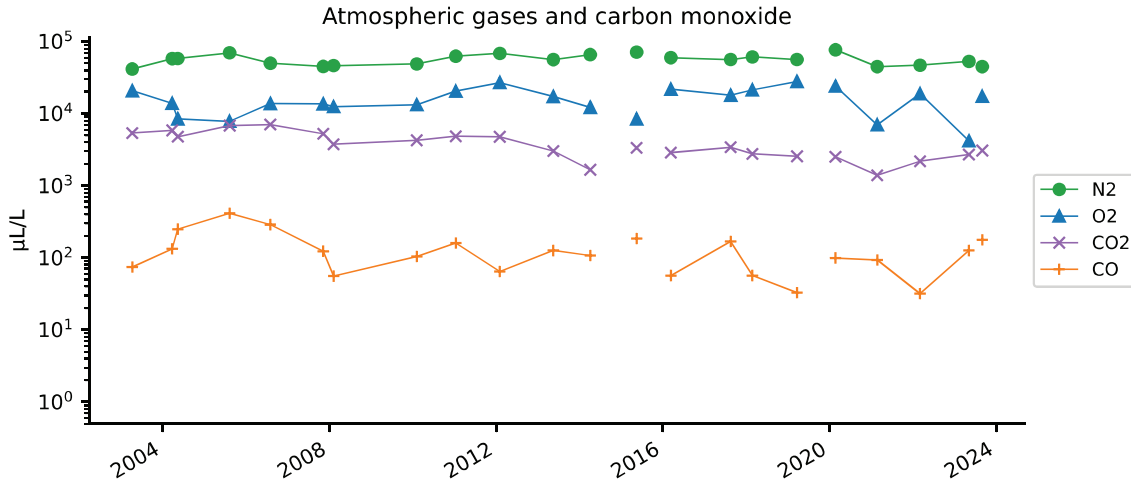
Lab report number	AA42278	
Sample date	2011-01-11	
Sample temp	25	°C
Aroclor 1242	41.0	mg/kg
Total PCB	41.0	mg/kg
PCB result	1	

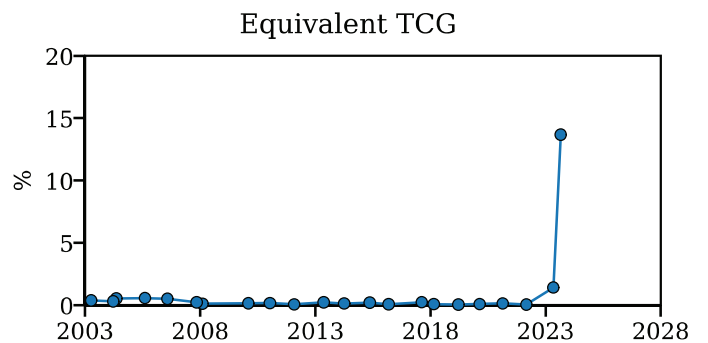
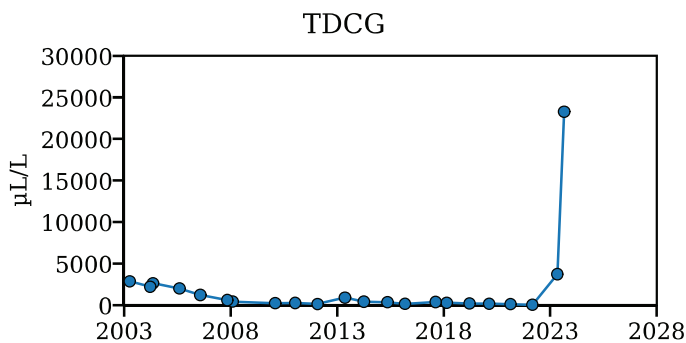
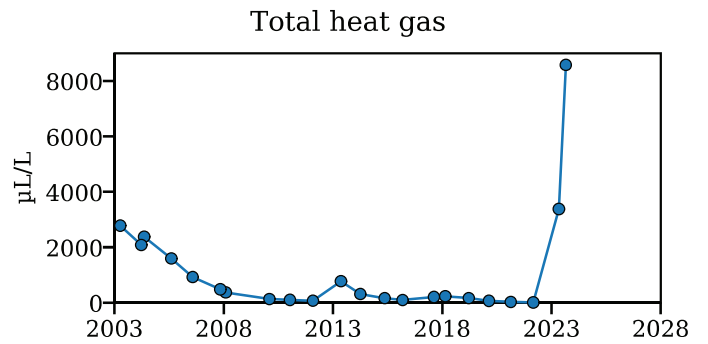
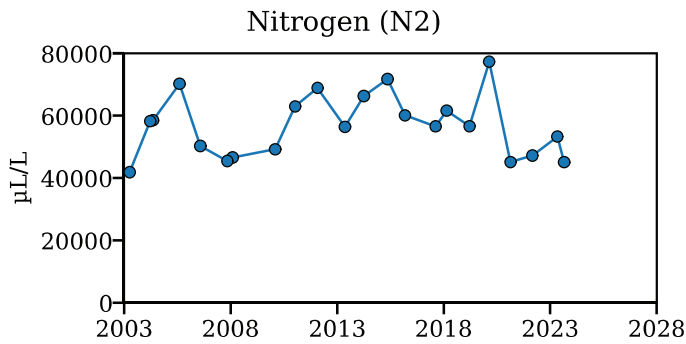
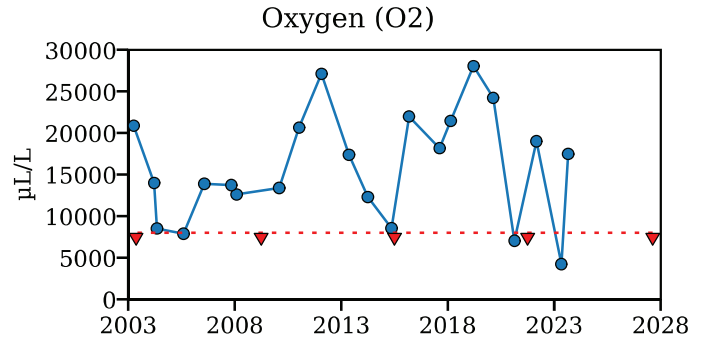
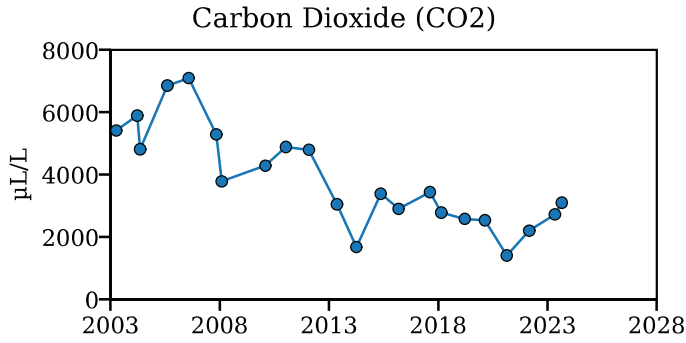
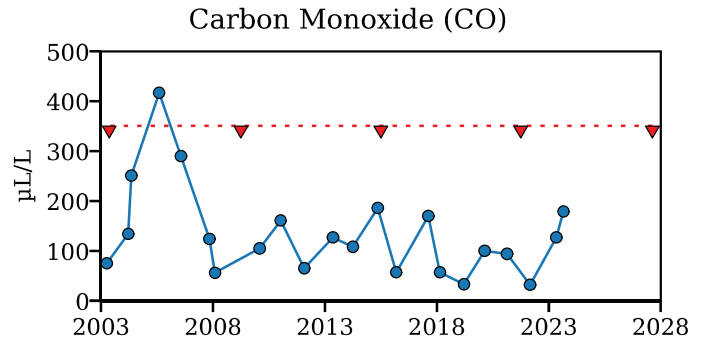
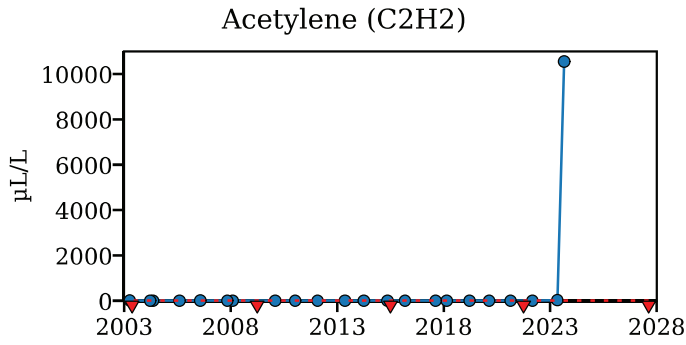
PCB Remarks

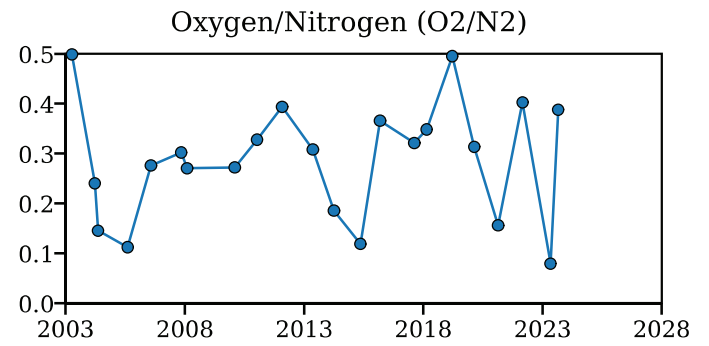
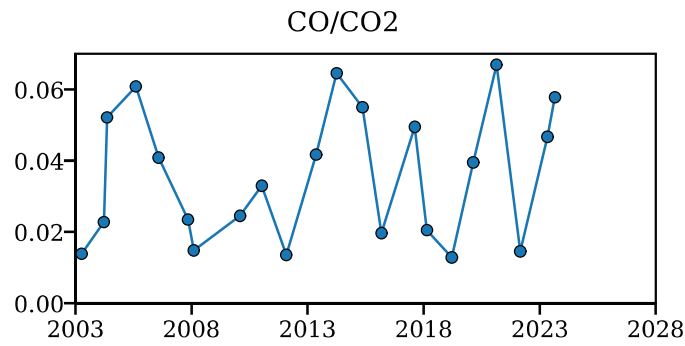
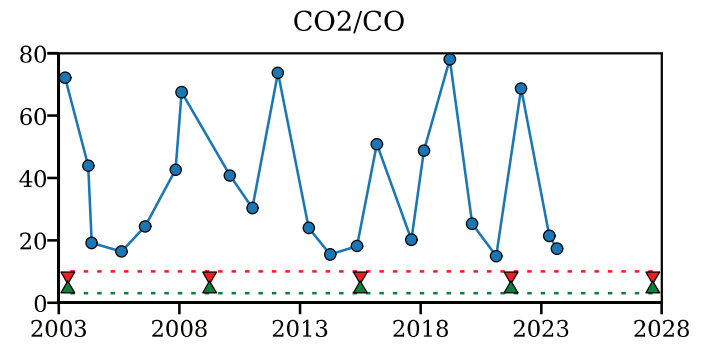
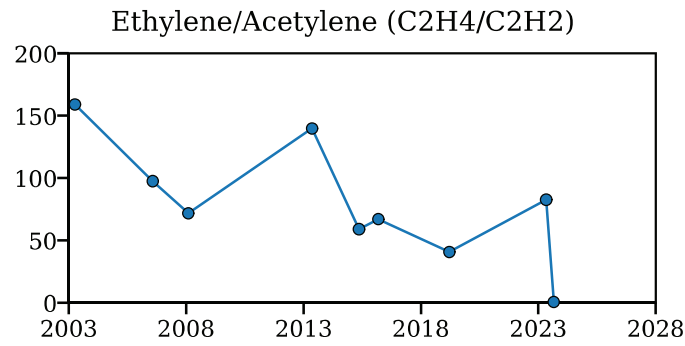
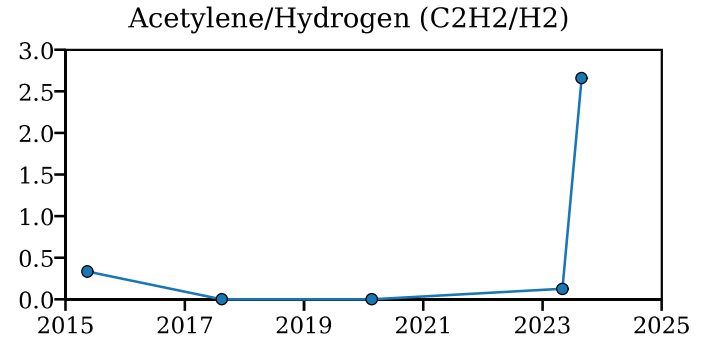
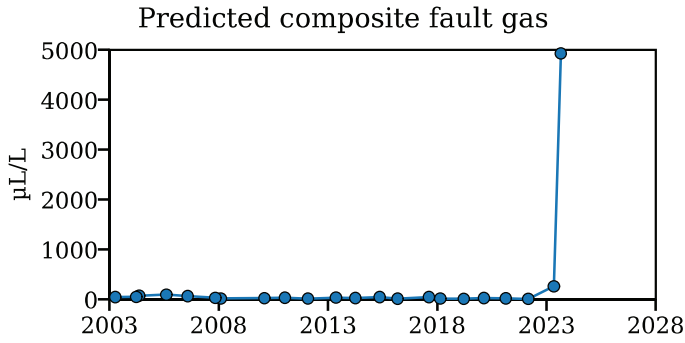
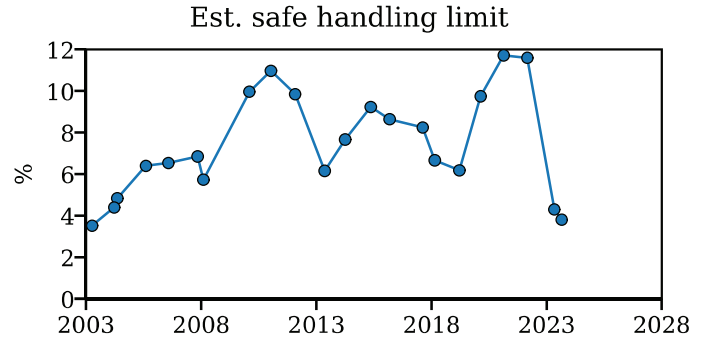
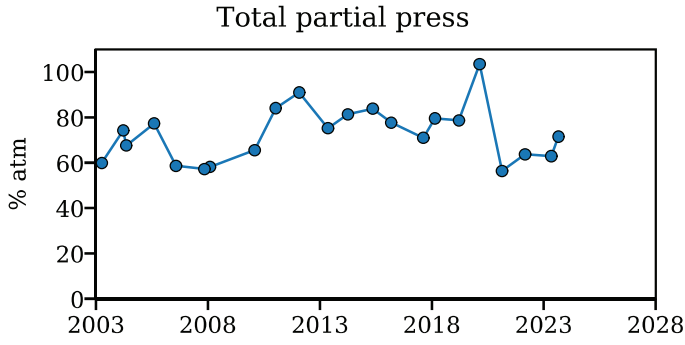
Not PCB contaminated. For a report of the last PCB sample, see the [PCB in Oil Report](#).

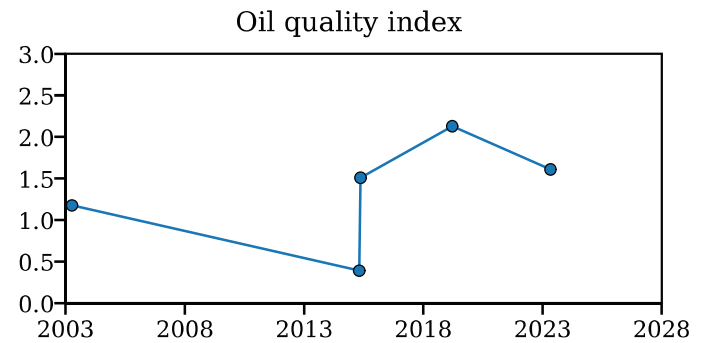
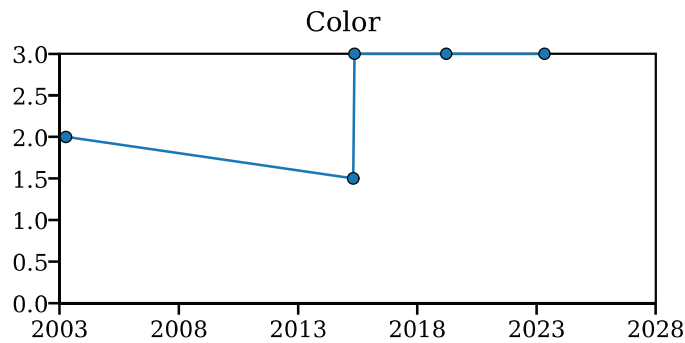
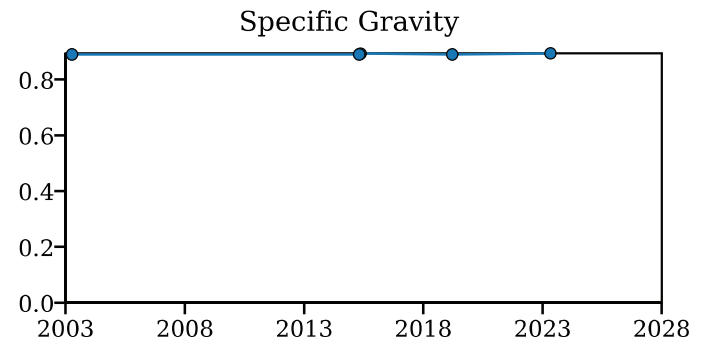
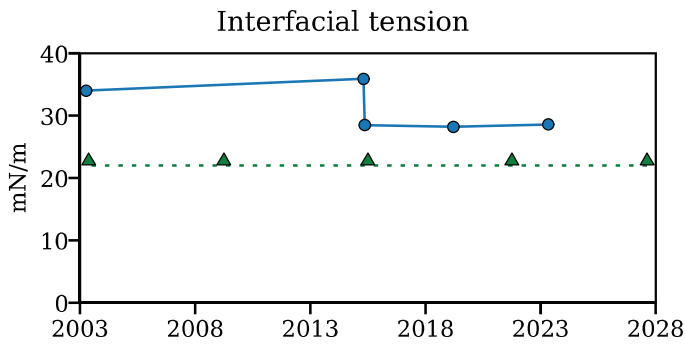
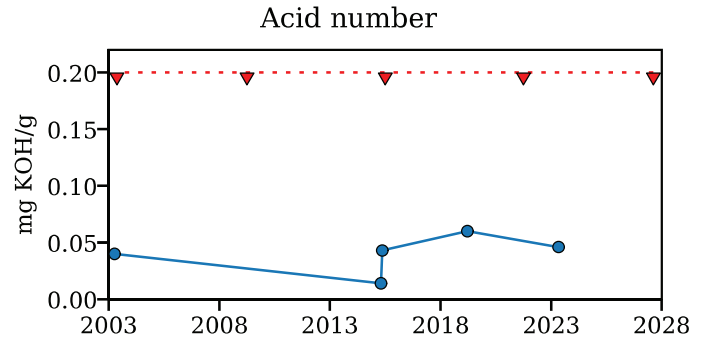
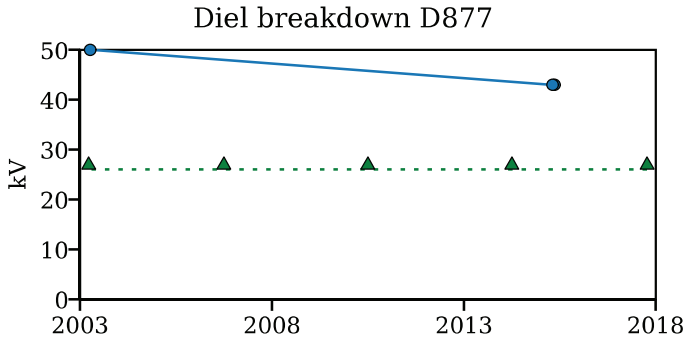
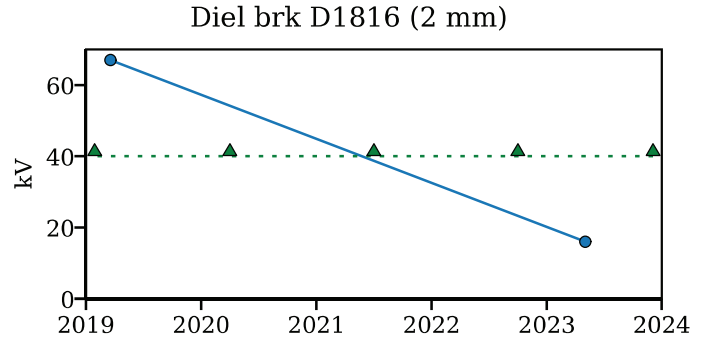
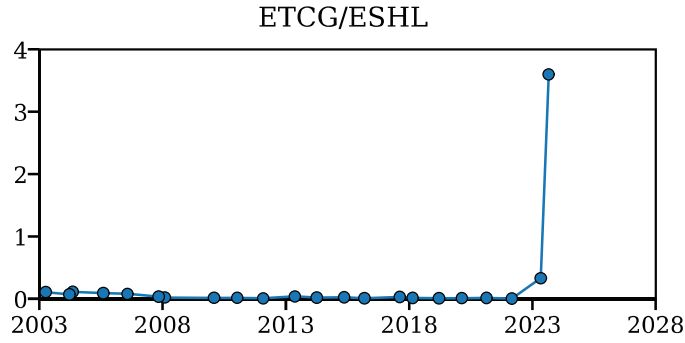
History Graphs and Diagnostic Charts

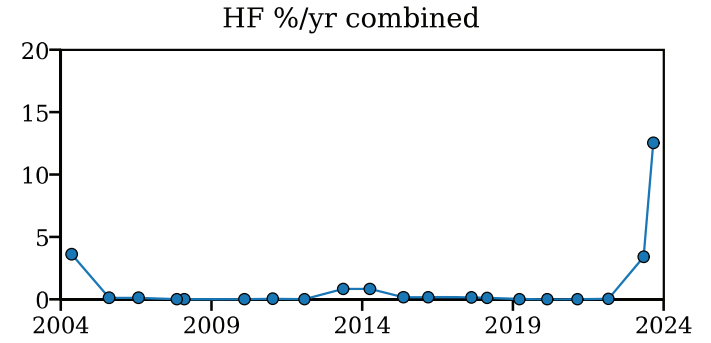
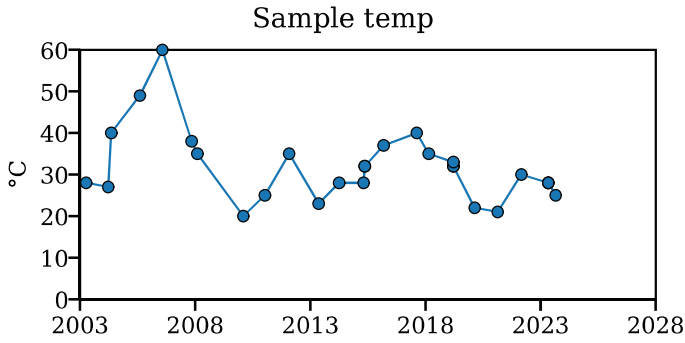
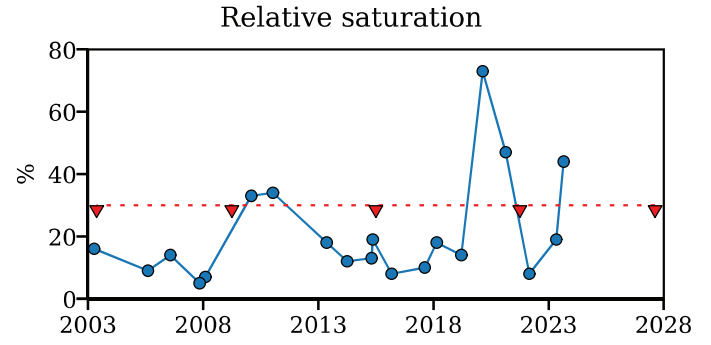
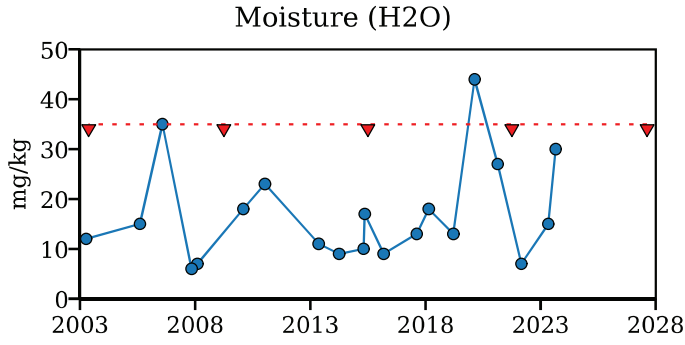












- Raw Data
- ▼--- Upper alert limit
- ▲--- Lower alert limit

I&E Exhibit 7

SUBSTATION NAME	BRADFORD WEST
BANK	1
BANK SIZE (MVA)	5.6
BANK SIZE (KVA)	5600
High side (kV)	34.5
Low side (kV)	12.47
TEMP RISE 1	55
TEMP RISE 2	65
TOP OIL TEMP (C)	N/A
PO Date	1971
SNPR MLOL (KVA)	5600
Comment	no fans, rectangular core
SNPR - summer normal planning rating MLOL - moderate loss of life	

I&E Exhibit 8
CONFIDENTIAL

**BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION**


Pennsylvania Public Utility Commission,	:	
Bureau of Investigation and Enforcement,	:	
Complainant	:	
	:	
v.	:	Docket No. C-2026-
	:	
FirstEnergy Pennsylvania Electric Company,	:	
Respondent	:	

CERTIFICATE OF SERVICE

I hereby certify that I have this day served a true copy of the foregoing **Formal Complaint (Non-Proprietary and Proprietary Version)** dated May 13, 2026 upon the parties, listed below, in accordance with the requirements of 52 Pa. Code § 1.54 (relating to service by a party).

Service by Certified Mail, Return Receipt, and Electronic Mail

Tori Giesler, Esq.
FirstEnergy Pennsylvania Electric Company
2800 Pottsville Pike
Reading, PA 16001
tgiesler@firstenergycorp.com



Colby B. Widdowson
Prosecutor
Bureau of Investigation and Enforcement
PA Attorney ID No. 326185
(717) 787-2139
cwiddowson@pa.gov