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# DGA–Duval Triangle Analysis for Early Thermal Fault Diagnosis of Transformer Oil

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***Abstract*** – *This study investigates the health condition of the T5 transformer oil at a geothermal power plant to enable early detection of thermal faults and support predictive maintenance. The assessment combined Dissolved Gas Analysis (DGA) with Total Dissolved Combustible Gas (TDCG) evaluation following IEEE C57.104–2019, Duval Triangle fault mapping, and dielectric tests including breakdown voltage (BV) and moisture content in accordance with IEEE C57.106–2015. Results revealed a TDCG level of 686 ppm (Condition 1) and a $CO_2$ concentration of 10,000 ppm. The hydrocarbon ratios—$CH_4$ 70.18%, $C_2H_4$ 29.24%, and $C_2H_2$ 0.58%—located the fault point within Duval zone T2 (300–700 °C), corresponding to a medium-temperature thermal fault. The moisture content of 29 ppm exceeded the recommended limit for transformers below 72.5 kV (<10 ppm), while the mean BV of 73.4 kV remained above the 40 kV minimum threshold, indicating acceptable dielectric strength despite moisture contamination. These findings suggest moderate thermal degradation occurring under high-moisture conditions, potentially reducing insulation reliability. Remedial actions such as oil filtration or dehydration, followed by trend monitoring of DGA and BV, are recommended to mitigate fault progression and enhance data-driven maintenance strategies.*

**Keywords** – *Dissolved Gas Analysis (DGA); Duval Triangle; Transformer Oil; Thermal Fault Diagnosis; Geothermal Power Plant.*

## I. Introduction

POWER-system reliability is fundamentally dependent on the operational health of transformers, which act as the backbone of electrical transmission and distribution networks. Among the various components of a transformer, the insulating oil plays a dual role as both a dielectric medium and a heat-transfer agent. Its degradation directly affects insulation integrity, cooling efficiency, and ultimately, system reliability and safety. Consequently, systematic monitoring of transformer oil has become an integral part of predictive and condition-based maintenance (CBM) programs aimed at minimizing outages, extending equipment lifetime, and optimizing asset management in modern power utilities [1–3].

In this context, Dissolved Gas Analysis (DGA) has emerged as the *de facto* standard for detecting early-stage faults within transformers. DGA provides valuable diagnostic information by analyzing the concentrations and ratios of key dissolved gases—$H_2$, $CH_4$, $C_2H_4$, $C_2H_6$, $C_2H_2$, CO, and $CO_2$—that evolve under various thermal and electrical stress conditions. Each gas or combination of gases serves as a signature for a specific fault mechanism, such as partial discharge, overheating, arcing, or insulation breakdown. The IEEE C57.104–2019 [4] standard provides comprehensive guidelines for interpreting these gases through Total Dissolved Combustible Gas (TDCG) concentration limits, fault classification boundaries, and severity grading systems.

Among DGA interpretation techniques, the Duval Triangle remains one of the most widely used diagnostic tools. Developed by Michel Duval at Hydro-Québec, this method employs a ternary diagram representing the relative proportions of $CH_4$, $C_2H_4$, and $C_2H_2$ to identify fault types ranging from low-temperature thermal degradation to high-energy discharges. The method's enduring popularity lies in its simplicity, graphical clarity, and robustness across transformer types and service conditions [5–8]. However, recent studies have identified several challenges in conventional applications—such as overlapping fault boundaries, ambigu-

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ous classification zones, and limited adaptability to non-standard operating conditions. To address these shortcomings, researchers have proposed a series of improvements, including modified Duval zones, hybrid ratio-triangle approaches, and intelligent algorithms leveraging machine learning techniques such as support vector machines, random forests, and deep neural networks [9–11]. These innovations aim to enhance fault discrimination accuracy and provide continuous, automated diagnostic capabilities within smart-grid infrastructures.

While DGA focuses primarily on gas-evolution mechanisms, complementary diagnostic parameters such as moisture content and breakdown voltage (BV) are equally vital for assessing an oil's dielectric performance. Excessive water in transformer oil reduces insulation resistance, accelerates cellulose paper degradation, and increases the likelihood of dielectric breakdown under transient stress. The IEEE C57.106–2015 standard establishes acceptance and maintenance criteria for mineral insulating oils and defines correlations between moisture concentration and BV thresholds. Empirical studies consistently show that reducing moisture improves dielectric strength and resistivity, whereas humidity elevation diminishes both [12–17]. Thus, integrating BV and moisture testing alongside DGA provides a holistic diagnostic framework for transformer condition assessment.

Transformers deployed in geothermal power plants experience unique operating environments compared to conventional grid transformers. Factors such as elevated ambient humidity, fluctuating load cycles, and persistent thermal stress from geothermal heat exchange can accelerate oil aging and gas generation. Consequently, reliable diagnostic methodologies are essential for early fault identification and preventive action in these demanding settings.

Beyond physical and chemical degradation, transformer oils in geothermal applications are often subject to additional stress factors such as contamination from dissolved minerals, micro-bubbles induced by pressure variations, and periodic moisture ingress due to sealing imperfections. These conditions complicate fault interpretation because gas evolution may arise from multiple overlapping mechanisms rather than a single dominant source. In such cases, combining DGA with dielectric and moisture analyses enables cross-verification of fault signatures, thereby minimizing false positives and improving diagnostic confidence.

Recent research trends emphasize the integration of multi-parameter datasets—combining DGA, BV, furan analysis, and dissolved moisture—in predictive models for transformer health indexing. Such models, often built using statistical inference or artificial intelligence frameworks, have demonstrated enhanced accuracy in fault classification and remaining-life estimation compared to conventional rule-based methods. Studies employing hybrid DGA–machine learning systems have achieved up to 95% classification accuracy in distinguishing between thermal, electrical, and combined faults [9, 10]. This shift from purely descriptive diagnostics to predictive analytics marks a paradigm transition in power-asset management toward data-driven, autonomous decision-making.

In Indonesia, where geothermal energy contributes significantly to the renewable energy portfolio, reliable transformer performance is crucial for uninterrupted plant operation. Given the high moisture levels and thermal cycling inherent to geothermal environments, conventional maintenance intervals are often inadequate for preventing incipient insulation failures. Therefore, establishing a localized diagnostic model based on empirical testing—such as DGA, Duval mapping, and BV analysis of in-service geothermal transformers—becomes strategically important. This approach not only strengthens maintenance planning but also supports national efforts toward sustainable and efficient power generation.

Against this technical background, the present study evaluates the insulating oil condition of the T5 transformer (2.5 MVA) installed at a geothermal power plant. The analysis integrates DGA and TDCG evaluation (per IEEE C57.104–2019), Duval Triangle mapping, and dielectric property testing—including BV and moisture content measurements in accordance with IEEE C57.106–2015. The study aims to provide a comprehensive early fault diagnosis, establish a baseline for oil health, and formulate data-driven maintenance recommendations to enhance operational reliability in geothermal power systems.

## II. Research Methods

### i. Object

The study was conducted at a geothermal power plant located at approximately 1,500 m above sea level. The research object was the T5 power transformer, which supplies the plant's internal loads (including cooling-tower fan motors), using oil as both the cooling and insulating medium with a capacity of about 2,000 L. Transformer T5 is an ONAN-cooled unit rated at 2.5 MVA, with a voltage of 6,000/400 V and a Dyn11 connection per the nameplate. Sampling and testing were performed by the Electrical Maintenance unit during 1 June–21 July 2023, with operating hours of 07:30–16:00 WIB (Western Indonesia Time).

**Table 1:** T5 Transformer Specifications Summary

| Parameters | Value |
|---|---|
| Manufacturer / Year of Operation | FUJI / 1986 |
| Installed Power | 2.5 MVA |
| Installed Voltage (HV/LV) | 6,000/400 V |
| Installed Current (HV/LV) | 241/3,608 A |
| Connection Symbol | Dyn11 |
| Cooling | ONAN |
| Total Oil | ~2,000 L |
| Frequency | 50 Hz |
| Insulation Level | HV: L1650/AC275; LV: AC3; LVN: AC3 |

At the time of this analysis, detailed plant records—such as monthly load cycles, oil-treatment dates, and breather replacement—were not available from the asset owner. Accordingly, interpretation in this paper is anchored to the sampling log and the instantaneous conditions observed during testing of the T5 transformer (2.5 MVA) under normal service at the geothermal power plant. Where recorded, ambient conditions at the yard (e.g., temperature) and operating settings at sampling are reported together with the test results; otherwise, they are marked as not available. The absence of historical loading and maintenance logs is explicitly acknowledged as a limitation and is further addressed in the Discussion and Future Work sections.

### *ii. Standard and Parameter*

The oil health evaluation comprised: (i) Dissolved Gas Analysis (DGA) for $H_2$, $CH_4$, $C_2H_6$, $C_2H_4$, $C_2H_2$, CO, and $CO_2$, along with calculation of Total Dissolved Combustible Gas (TDCG); (ii) fault-type classification using the Duval Triangle based on the $CH_4$–$C_2H_4$–$C_2H_2$ proportions; and (iii) breakdown-voltage (BV) and moisture-content testing as indicators of the oil's dielectric strength. DGA/TDCG interpretation followed IEEE C57.104-2019; Duval mapping and diagnosis followed IEC 60599-2022; and acceptance/maintenance criteria for BV and moisture followed IEEE C57.106-2015 according to the transformer's voltage class.

DGA was performed using gas chromatography on oil samples; BV was tested with an oil BDV tester using the standard 2.5 mm electrode gap with $\geq$6 repetitions to obtain a mean; moisture content was measured by Karl Fischer titration (volumetric/coulometric). Quality control included replicates, blank/standard checks, and consistency checks across repetitions.

Insufficient evidence: instrument make/model (GC, BDV tester, KF titrator), most recent calibration certificates, test temperature and degassing conditions, BV electrode geometry, sampling flush/purge procedure, and sample chain of custody.

This section establishes the parameters and standard thresholds used as evaluation references. Table 2 lists breakdown-voltage (BV) criteria by transformer voltage class; BV is used as an indicator of the oil's dielectric strength, noting that increasing moisture reduces BV.

**Table 2:** Breakdown Voltage Standards for Transformer Oil [18]

| CATEGORY | GOOD | GOOD ENOUGH | BAD |
|---|---|---|---|
| >170 kV | >60 | 50–60 | <50 |
| 72.5–170 kV | >50 | 40–50 | <40 |
| <72.5 kV | >40 | 30–40 | <30 |

Table 3 presents moisture-content limits by voltage class. These limits are used to assess oil suitability: values within the "good" category indicate acceptable moisture levels, whereas values exceeding the "bad" threshold indicate the need for corrective action before dielectric degradation develops.

**Table 3:** Water Content Standards for Transformer Oil [18]

| CATEGORY | GOOD | GOOD ENOUGH | BAD |
|---|---|---|---|
| >170 kV | <5 | 5–10 | >10 |
| 72.5–170 kV | <5 | 5–15 | >15 |
| <72.5 kV | <10 | 10–25 | >25 |

Table 4 provides limits for dissolved-gas concentrations ($H_2$, $CH_4$, $C_2H_2$, $C_2H_4$, $C_2H_6$, CO, $CO_2$) along with TDCG ranges for classifying Conditions 1–4. This classification serves as a severity scale—from Condition 1 (satisfactory operation) to Condition 4 (very high deterioration/failure risk)—and forms the basis for determining the need for further investigation and maintenance follow-up.

**Table 4:** Dissolved Gas Concentration Limits (ppm) [4]

| Status | $H_2$ | $CH_4$ | $C_2H_2$ | $C_2H_4$ | $C_2H_6$ | CO | TDCG |
|---|---|---|---|---|---|---|---|
| State 1 | 100 | 120 | 35 | 50 | 65 | 350 | 720 |
| State 2 | 101–700 | 121–400 | 36–50 | 51–100 | 66–100 | 351–570 | 721–1,920 |
| State 3 | 700–1,800 | 401–1,000 | 51–80 | 101–200 | 101–150 | 571–1,400 | 1,921–4,630 |
| State 4 | >1,800 | >1,000 | >80 | >200 | >150 | >1,400 | >4,630 |

Dissolved Gas Analysis (DGA) was carried out using a gas chromatograph equipped with thermal conductivity and flame ionization detectors, operated with helium as the carrier gas. The instrument type, calibration, and operating parameters were verified according to the laboratory's QA record to ensure traceability and reproducibility of the measurements.

Breakdown-voltage (BV) tests were performed with a portable oil BDV tester using hemispherical brass electrodes spaced at 2.5 mm, and a voltage-rise rate of 2 kV/s until dielectric breakdown occurred. Each sample was tested six times to obtain the mean and standard deviation.

Moisture content was measured by Karl Fischer coulometric titration using a calibrated titrator with oven heating at 120 °C. Calibration verification was conducted with a water standard before each batch. All instruments operated under controlled laboratory conditions (23 ± 2 °C) and complied with the traceability and calibration requirements of the testing laboratory.

### *iii. Sampling Procedure and Testing*

Oil sampling was conducted on transformer T5 at the geothermal power plant during 1 June–21 July 2023 by the Electrical Maintenance unit. Samples were taken and handled according to local procedures to prevent contamination; however, details on the container/media, purging, and chain of custody were not specified in the report. The samples were then analyzed by Dissolved Gas Analysis (DGA) using gas chromatography to obtain the concentrations of $H_2$, $CH_4$, $C_2H_6$, $C_2H_4$, $C_2H_2$, CO, and $CO_2$; TDCG was calculated as an aggregate degradation indicator and classified into condition categories (1–4).

The hydrocarbon composition was normalized to $\%CH_4$, $\%C_2H_4$, and $\%C_2H_2$ using the equations provided in the report, and plotted on the Duval Triangle to identify the fault type (T1/T2/T3/D1/D2/DT/PD). Dielectric strength was tested via breakdown voltage (BV) using the standard 2.5 mm electrode gap with multiple repetitions ($\geq 6$) to obtain a mean value, as reported in Table 2. Moisture content was measured and reported as part of the DGA table (water content). The gas concentrations, TDCG value, Duval zone, mean BV, and moisture content were synthesized against standard thresholds to conclude the oil health status and develop maintenance recommendations.

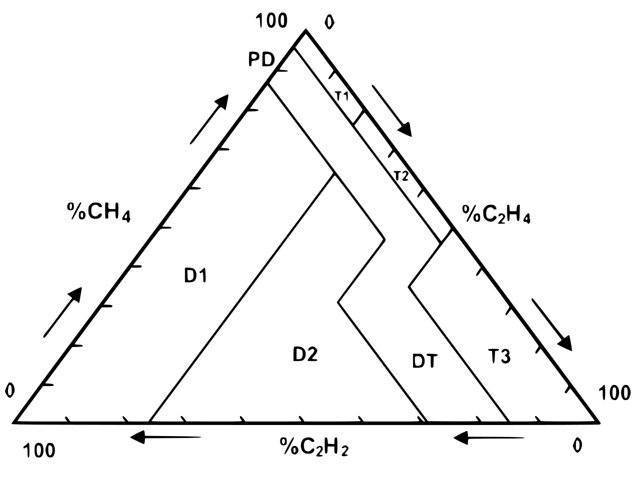


**Figure 1:** Duval Triangle for $CH_4$–$C_2H_4$–$C_2H_2$ proportions.

### *iv. Processing and Decision Rules*

The DGA data were cleaned of incomplete entries, then compiled by gas component ($H_2$, $CH_4$, $C_2H_6$, $C_2H_4$, $C_2H_2$, CO, $CO_2$) in ppm. TDCG was determined and classified according to IEEE C57.104-2019 condition categories (1–4) to assess severity. The hydrocarbon proportions $CH_4$–$C_2H_4$–$C_2H_2$ were normalized to $\%CH_4$, $\%C_2H_4$, and $\%C_2H_2$ using standard normalization equations; the resulting coordinates were plotted on the Duval Triangle (IEC 60599:2022) to identify the fault type (T1/T2/T3/D1/D2/DT/PD).

Breakdown voltage (BV) was computed as the mean of $\geq 6$ repetitions across a 2.5 mm electrode gap and then evaluated against IEEE C57.106-2015 thresholds for the transformer's voltage class. Moisture content was reported in ppm and compared with the suitability limits for transformers $<72.5$ kV per IEEE C57.106-2015. All indicators (TDCG, Duval zone, mean BV, and moisture content) were synthesized into a combined decision rule to determine the oil health status and recommend actions (filtration/dehydration and trend monitoring).

**Table 5:** Duval Triangle Disturbance Zone Code

| Zone | Indication of Disturbance |
|---|---|
| T1 | Thermal fault, T $\leq$ 300 °C |
| T2 | Thermal fault, 300 °C $<$ T $\leq$ 700 °C |
| T3 | Thermal fault, T $>$ 700 °C |
| D1 | Discharges of low energy |
| D2 | Discharges of high energy |
| DT | Thermal mixture and electrical fault |
| PD | Partial discharges |

Measurement uncertainties were evaluated to assess the reliability of the test results. Type A uncertainty for the BV test was derived from six repeated measurements, yielding a relative standard deviation of 11.4% and a 95% confidence interval of $\pm 8.8$ kV. Type B uncertainty was estimated from the manufacturer's instrument specifications, including $\pm(2\% + 0.5$ kV) for the BDV tester and $\pm(0.2$ ppm + 3%) for the Karl Fischer titrator. For DGA, combined uncertainty was calculated as:

$$u_{\text{TDCG}} = \sum u_i^2$$

where $u_{\text{TDCG}}$ represents the uncertainty of each dissolved-gas component.

Environmental factors such as sampling temperature, residual gas loss, and atmospheric moisture were recognized as potential bias sources. These effects were minimized by purging the sampling line before oil extraction, sealing the vials immediately after filling, and performing analysis within 24 h of collection. The resulting combined uncertainty for TDCG and moisture content was within ±5%, confirming the robustness of the measurement data.

## III. Results and Discussion

### i. *Summary of T5 Transformer Oil Test Data*

**Figure 2:** Transformer oil illustration and sampling setup.

This section presents the key measurement results for the T5 transformer oil as the basis for subsequent analyses. Table 6 reports the Dissolved Gas Analysis (DGA) outputs—dissolved-gas concentrations of $H_2$, $CH_4$, $C_2H_6$, $C_2H_4$, $C_2H_2$, CO, and $CO_2$ (ppm); the TDCG value (ppm) as the sum of combustible gases ($CO_2$ is not considered combustible); and supporting parameters including moisture content (ppm), oil temperature (°C), and oil level (0–75 indicator scale).

**Table 6:** Gas Test Data on T5 Transformer Oil

| Component | Symbol | Measure |
|---|---|---|
| Hydrogen | $H_2$ | 100 ppm |
| Methane | $CH_4$ | 120 ppm |
| Carbon Monoxide | CO | 350 ppm |
| Carbon Dioxide | $CO_2$ | 10,000 ppm |
| Ethylene | $C_2H_4$ | 50 ppm |
| Ethane | $C_2H_6$ | 65 ppm |
| Acetylene | $C_2H_2$ | 1 ppm |
| TDCG | | 686 ppm |
| Water | $H_2O$ | 29 ppm |
| Temperature | Oil Temp | 28 °C |
| Oil Level | 0–75 scale | 30 Level |

Table 7 presents the breakdown-voltage (BV) measurements across a 2.5 mm electrode gap, performed in six repetitions. The BV summary statistics are $73.4 \pm 8.4$ kV ($n = 6$), with a range of 59.4–80 kV. These data provide the basis for the evaluation in Subsection ii.

**Table 7:** Breakdown Voltage Measurement Data of T5 Transformer (Electrode Gap 2.5 mm)

| Voltage Breakdown Testing | kV/cm |
|---|---|
| Test 1 | 59.4 |
| Test 2 | 80.0 |
| Test 3 | 76.2 |
| Test 4 | 66.9 |
| Test 5 | 77.7 |
| Test 6 | 80.0 |
| Average ± SD (kV) | 73.4 ± 8.4 |

### ii. *DGA Results and TDCG Classification*

Based on the data in Table 6, the measured dissolved-gas concentrations are $H_2$ 100 ppm, $CH_4$ 120 ppm, $C_2H_6$ 65 ppm, $C_2H_4$ 50 ppm, $C_2H_2$ 1 ppm, CO 350 ppm, and $CO_2$ 10,000 ppm. The TDCG is calculated as the sum of the six combustible gases (excluding $CO_2$):

$$\text{TDCG} = 100 + 120 + 65 + 50 + 1 + 350 = 686 \text{ ppm}.$$

According to IEEE C57.104-2019 thresholds, 686 ppm corresponds to *Condition 1*. This finding indicates that, from the perspective of combustible-gas accumulation, the T5 transformer oil is at a low alert level. Nevertheless, the $CO_2$ content of 10,000 ppm is not part of TDCG and is recorded separately as contextual evidence of oxidation.

### iii. *Duval Triangle Mapping and Disturbance Identification*

The hydrocarbon proportions were normalized to the sum of $CH_4$, $C_2H_4$, and $C_2H_2$ from Table 6. The resulting fractions are:

$$CH_4 = 70.18\%, \quad C_2H_4 = 29.24\%, \quad C_2H_2 = 0.58\%.$$

When plotted on the Duval Triangle, these coordinates fall in zone T2, representing a thermal fault with a temperature range of 300–700 °C. The very small $C_2H_2$ value indicates the absence of the high-energy discharges typical of D2-type faults. The dominance of $CH_4$ and $C_2H_4$ is consistent with oil heating at a medium severity level.

### iv. *Dielectric Strengths and Humidity*

Dielectric strength was assessed via breakdown-voltage (BV) testing across a 2.5 mm electrode gap with six repetitions. The recorded values were 59.4, 80.0, 76.2, 66.9, 77.7, and 80.0 kV, yielding a mean of 73.4 kV. This average exceeds the acceptance threshold for the relevant voltage class and therefore indicates

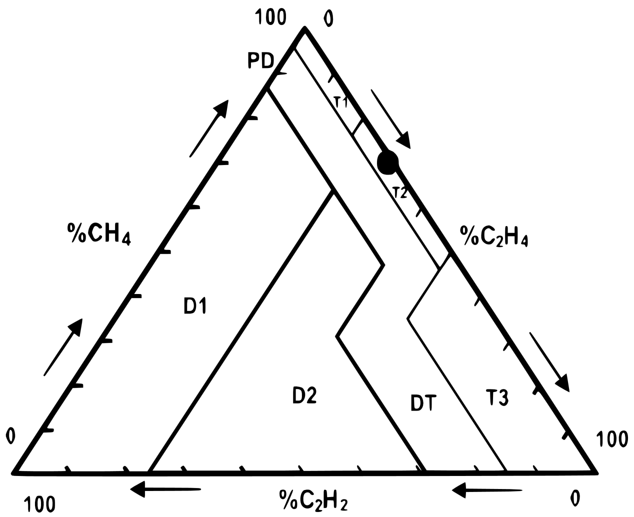


**Figure 3:** Duval Triangle mapping showing T5 fault zone (T2 region).

adequate instantaneous insulation performance [4]. The inter-trial variation ranged from approximately 59 to 80 kV, which remains acceptable for field testing under real-sample conditions.

Oil moisture, expressed as water content, measured 29 ppm. For transformers rated below 72.5 kV, this value lies above the range commonly categorized as *good*. In principle, increased moisture reduces the dielectric strength of oil and accelerates cellulose paper degradation, thereby elevating the risk of BV reduction under fluctuating operating conditions [12, 19].

The discrepancy between a high mean BV and a moisture level exceeding recommendations indicates that the sample could still withstand breakdown at the time of testing, but its safety margin may narrow if the moisture is not addressed. Operationally, the combined BV and moisture results warrant corrective measures such as oil dehydration or filtration to lower water content, followed by repeat BV testing after treatment. Periodic monitoring of moisture and BV is recommended to track moisture dynamics and their impact on dielectric strength.

The BV values obtained from six repetitions were 59.4, 80.0, 76.2, 66.9, 77.7, and 80.0 kV, resulting in a mean of 73.4 kV with a standard deviation of 8.4 kV. The 95% confidence interval ($CI_{95}$), calculated using Student's $t$-distribution for $n = 6$, was $73.4 \pm 8.8$ kV, corresponding to a range of 64.6–82.2 kV. The relative coefficient of variation (CV) of 11.4% indicates acceptable repeatability for field BDV measurements.

Although the analysis was limited to a single transformer, the obtained BV range and confidence limits are consistent with results from comparable units reported in recent field studies [13, 15, 20]. These studies similarly reported BV values between 65–85 kV for in-service mineral oils with moisture levels of 20–30 ppm, supporting the general applicability of the observed dielectric strength. Therefore, the statistical reliability of the BV data is considered adequate for interpreting insulation health under the observed moisture condition.

### *v. Multi-indicator Synthesis and Recommendation*

The maintenance decision in this study follows a concise, indicator-driven flow from oil diagnostics to actionable interventions. The flow prioritizes (i) dissolved-gas interpretation (Duval zone and TDCG), (ii) dielectric strength at test time (BV at 2.5 mm), and (iii) moisture content as the primary risk modifier. The intent is to standardize actions, reduce ambiguity for borderline DGA cases, and couple any corrective treatment with post-treatment verification and trend monitoring.

**Table 8:** Indicator to Action Matrix

| Indicator set | Interpretation | Action |
|---|---|---|
| Duval = T1, BV stable, moisture low | Thermal–low / benign | Routine monitoring (quarterly) |
| Duval = T2 with low $C_2H_2$; BV stable; moisture elevated | Thermal–medium; dielectric margin at risk | Dehydration/filtration, then retest; move to monthly monitoring temporarily |
| Duval = D1/D2 or BV downtrend | Discharge risk / paper stress | Post-treatment verification; if persists then targeted inspection / planned outage |
| Any TDCG uptrend after treatment | Active fault or ingress | Escalate monitoring; correlate with load/cooling; plan intervention |

The combined indicators depict a nonuniform situation. The calculated TDCG of 686 ppm indicates a low alert level if assessed solely from the accumulation of combustible gases. However, Duval Triangle mapping places the hydrocarbon composition in zone T2, consistent with a medium-level thermal fault. The moisture content reaches 29 ppm—exceeding the range commonly considered "good" for transformers rated below 72.5 kV—while the mean BV of 73.4 kV across a 2.5 mm gap still demonstrates adequate instantaneous withstand capability during testing [20].

This combination implies localized heating that has not yet produced high gas accumulation but is occurring under moist-oil conditions, thereby potentially reducing the dielectric margin under dynamic operation.

The short-term technical priority is moisture remediation. Recommended actions include vacuum dehydration or hot-oil circulation with filtration, followed by replacement or drying of absorbents (silica gel); inspection and resealing of potential moisture ingress points (gaskets, bushing seals, conservator/diaphragm);

and verification of breather function [21, 22]. Given the T2 indication, inspection for localized heat sources is warranted: testing of high-current joints, review of load profile and oil temperature, and examination of the cooling system to ensure the absence of hot spots due to insufficient oil flow or increased contact resistance.

After corrective actions, tiered monitoring is advised to confirm stabilization. Perform DGA monthly for the first three months, then quarterly, with attention to the rate of change of key gases and any shift in the Duval zone. Monitor moisture weekly until it stabilizes below 10 ppm, then monthly. Repeat BV testing post-treatment and at least once more after one full operating cycle; a practical acceptance criterion is a stable mean BV (session-to-session change $\leq \pm 5$ kV) with no consistent decline correlated with rising moisture. If acetylene increases or the Duval coordinates shift toward T3/D1/D2, schedule an in-depth inspection and a planned outage.

Recent developments in machine-learning-based DGA interpretation have aimed to improve consistency in fault classification, particularly for samples that lie near the boundaries of the Duval zones. Studies combining conventional DGA features with supervised learning methods such as support-vector machines, random-forest classifiers, and deep neural networks have demonstrated improved diagnostic accuracy over rule-based approaches [10, 11].

The gas pattern observed in this study—high $CH_4$ and $C_2H_4$ with negligible $C_2H_2$—placing the transformer oil within Duval zone T2 matches the thermal-medium class identified in those hybrid models, where medium-temperature faults (300–700 °C) are characterized by low acetylene generation and moderate methane–ethylene ratios. This consistency supports the validity of classical Duval interpretation and provides a valuable ground-truth dataset for training or validating future DGA–ML hybrid frameworks under real operating conditions. Integrating such hybrid diagnostic systems into routine transformer monitoring could enhance early-warning capability and enable adaptive maintenance scheduling, aligning with condition-based maintenance (CBM) practices increasingly adopted in geothermal and power-utility environments.

## IV. Conclusion

This study evaluates the health of the T5 transformer oil at a geothermal power plant using DGA/TDCG, Duval Triangle mapping, and tests of dielectric strength (BV) and moisture content. The measured TDCG is 686 ppm (Condition 1 in the TDCG classification), indicating that the accumulation of combustible gases remains at a low alert level. The hydrocarbon fractions—$CH_4$ = 70.18%, $C_2H_4$ = 29.24%, and $C_2H_2$ = 0.58%—map the point to Duval Triangle zone T2, which indicates a medium-level thermal fault (approximately 300–700 °C). A BV test across a 2.5 mm gap with six repetitions yielded a mean of 73.4 kV, demonstrating adequate instantaneous withstand capability; however, the moisture content of 29 ppm exceeds the “good” range for transformers rated below 72.5 kV, potentially reducing the dielectric margin in operation.

Synthesizing these indicators suggests localized heating that has not yet led to high gas accumulation but is occurring under moist-oil conditions. Recommended technical actions include oil dehydration/filtration to reduce moisture, investigation of potential localized heat sources (high-current joints, cooling flow, and resistive contacts), and periodic trend monitoring of DGA, moisture content, and BV to confirm post-treatment stabilization.

## V. Future Work

Limitations of this study include its focus on a single transformer unit and a one-time snapshot without a time series. The unavailability of detailed operational and maintenance logs, as noted in Section 2.1, also constrains trend analysis and correlation with plant conditions.

Going forward, longitudinal monitoring over multiple operating cycles will enable more robust temporal modeling of gas evolution and dielectric degradation. Future work should incorporate additional parameters such as furans, tan $\delta$, interfacial tension, acidity, and comparisons across transformers of the same type within the same plant to strengthen inference and improve maintenance-decision accuracy.

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