



Designation: D4378 – 20

Standard Practice for In-Service Monitoring of Mineral Turbine Oils for Steam, Gas, and Combined Cycle Turbines¹

This standard is issued under the fixed designation D4378; the number immediately following the designation indicates the year of original adoption or, in the case of revision, the year of last revision. A number in parentheses indicates the year of last reapproval. A superscript epsilon (ϵ) indicates an editorial change since the last revision or reapproval.

INTRODUCTION

The in-service monitoring of turbine oils has long been recognized by the power-generation industry as being necessary to ensure long, trouble-free operation of turbines.

The two main types of stationary turbines used for power generation are steam and gas turbines; the turbines can be used as individual turbines, or can be configured as combine cycle turbines. Combined cycle turbines are of two types; the first type connects a gas turbine with a steam turbine, with separate lubricant circuits, and the second type mounts a steam and a gas turbine on the same shaft and has a common lubricant circuit. The lubrication requirements are quite similar but there are important differences in that gas turbine oils are subjected to significantly higher localized “hot spot” temperatures and water contamination is less likely. Steam turbine oils are normally expected to last for many years. In some turbines up to 20 years of service life has been obtained. Gas turbine oils, by comparison, have a shorter service life from 2 to 5 years depending on severity of the operating conditions. One of the benefits of the gas turbine is the ability to respond quickly to electrical power generation dispatching requirements. Consequently, a growing percentage of modern gas turbines are being used for peaking or cyclic duty (frequent unit stops and starts) that subjects the lubricant to variable conditions (very high down to ambient temperatures), which put additional stresses on the lubricant.

This practice is designed to assist the user to validate the condition of the lubricant through its life cycle by carrying out a meaningful program of sampling and testing of oils in service. This practice is performed in order to collect data and monitor trends which suggest any signs of lubricant deterioration and to ensure a safe, reliable, and cost-effective operation of the monitored plant equipment.

1. Scope*

1.1 This practice covers the requirements for the effective monitoring of mineral turbine oils in service in steam and gas turbines, as individual or combined cycle turbines, used for power generation. This practice includes sampling and testing schedules to validate the condition of the lubricant through its life cycle and by ensuring required improvements to bring the present condition of the lubricant within the acceptable targets. This practice is not intended for condition monitoring of lubricants for auxiliary equipment; it is recommended that the appropriate practice be consulted (see Practice [D6224](#)).

1.2 *This standard does not purport to address all of the safety concerns, if any, associated with its use. It is the responsibility of the user of this standard to establish appropriate safety, health, and environmental practices and determine the applicability of regulatory limitations prior to use.*

1.3 *This international standard was developed in accordance with internationally recognized principles on standardization established in the Decision on Principles for the Development of International Standards, Guides and Recommendations issued by the World Trade Organization Technical Barriers to Trade (TBT) Committee.*

2. Referenced Documents

2.1 ASTM Standards:²

¹ This practice is under the jurisdiction of ASTM Committee [D02](#) on Petroleum Products, Liquid Fuels, and Lubricants and is the direct responsibility of Subcommittee [D02.C0.01](#) on Turbine Oil Monitoring, Problems and Systems.

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² For referenced ASTM standards, visit the ASTM website, www.astm.org, or contact ASTM Customer Service at service@astm.org. For *Annual Book of ASTM Standards* volume information, refer to the standard's Document Summary page on the ASTM website.

*A Summary of Changes section appears at the end of this standard

- D92** Test Method for Flash and Fire Points by Cleveland Open Cup Tester
- D130** Test Method for Corrosiveness to Copper from Petroleum Products by Copper Strip Test
- D445** Test Method for Kinematic Viscosity of Transparent and Opaque Liquids (and Calculation of Dynamic Viscosity)
- D664** Test Method for Acid Number of Petroleum Products by Potentiometric Titration
- D665** Test Method for Rust-Preventing Characteristics of Inhibited Mineral Oil in the Presence of Water
- D892** Test Method for Foaming Characteristics of Lubricating Oils
- D943** Test Method for Oxidation Characteristics of Inhibited Mineral Oils
- D974** Test Method for Acid and Base Number by Color-Indicator Titration
- D1401** Test Method for Water Separability of Petroleum Oils and Synthetic Fluids
- D1500** Test Method for ASTM Color of Petroleum Products (ASTM Color Scale)
- D2272** Test Method for Oxidation Stability of Steam Turbine Oils by Rotating Pressure Vessel
- D2273** Test Method for Trace Sediment in Lubricating Oils
- D2422** Classification of Industrial Fluid Lubricants by Viscosity System
- D2668** Test Method for 2,6-*di-tert*-Butyl- *p*-Cresol and 2,6-*di-tert*-Butyl Phenol in Electrical Insulating Oil by Infrared Absorp
- D3427** Test Method for Air Release Properties of Hydrocarbon Based Oils
- D4057** Practice for Manual Sampling of Petroleum and Petroleum Products
- D4175** Terminology Relating to Petroleum Products, Liquid Fuels, and Lubricants
- D4898** Test Method for Insoluble Contamination of Hydraulic Fluids by Gravimetric Analysis
- D5185** Test Method for Multielement Determination of Used and Unused Lubricating Oils and Base Oils by Inductively Coupled Plasma Atomic Emission Spectrometry (ICP-AES)
- D6224** Practice for In-Service Monitoring of Lubricating Oil for Auxiliary Power Plant Equipment
- D6304** Test Method for Determination of Water in Petroleum Products, Lubricating Oils, and Additives by Coulometric Karl Fischer Titration
- D6439** Guide for Cleaning, Flushing, and Purification of Steam, Gas, and Hydroelectric Turbine Lubrication Systems
- D6810** Test Method for Measurement of Hindered Phenolic Antioxidant Content in Non-Zinc Turbine Oils by Linear Sweep Voltammetry
- D6971** Test Method for Measurement of Hindered Phenolic and Aromatic Amine Antioxidant Content in Non-zinc Turbine Oils by Linear Sweep Voltammetry
- D7042** Test Method for Dynamic Viscosity and Density of Liquids by Stabinger Viscometer (and the Calculation of Kinematic Viscosity)
- D7155** Practice for Evaluating Compatibility of Mixtures of Turbine Lubricating Oils
- D7464** Practice for Manual Sampling of Liquid Fuels, Associated Materials and Fuel System Components for Microbiological Testing
- D7647** Test Method for Automatic Particle Counting of Lubricating and Hydraulic Fluids Using Dilution Techniques to Eliminate the Contribution of Water and Interfering Soft Particles by Light Extinction
- D7669** Guide for Practical Lubricant Condition Data Trend Analysis
- D7687** Test Method for Measurement of Cellular Adenosine Triphosphate in Fuel and Fuel-associated Water With Sample Concentration by Filtration
- D7720** Guide for Statistically Evaluating Measurand Alarm Limits when Using Oil Analysis to Monitor Equipment and Oil for Fitness and Contamination
- D7843** Test Method for Measurement of Lubricant Generated Insoluble Color Bodies in In-Service Turbine Oils using Membrane Patch Colorimetry
- D7978** Test Method for Determination of the Viable Aerobic Microbial Content of Fuels and Associated Water—Thixotropic Gel Culture Method
- D8072** Classification for Reporting Solids and Insoluble Water Contamination of Hydrocarbon-Based Petroleum Products When Analyzed by Imaging Instrumentation
- D8112** Guide for Obtaining In-Service Samples of Turbine Operation Related Lubricating Fluid
- F311** Practice for Processing Aerospace Liquid Samples for Particulate Contamination Analysis Using Membrane Filters
- F312** Test Methods for Microscopical Sizing and Counting Particles from Aerospace Fluids on Membrane Filters
- 2.2 *International Organization for Standardization Standards:*³
- ISO 4406** Hydraulic fluid power—Fluids—Method for Coding the Level of Contamination by Solid Particles, Second Edition, 1999
- ISO 4407** Hydraulic Fluid Power—Fluid Contamination—Determination of Particulate Contamination by Counting Method Using an Optical Microscope, Second Edition, 2002
- ISO 11500** Hydraulic Fluid Power—Determination of the Particulate Contamination Level of a Liquid Sample by Automatic Particle Counting Using the Light Extinction, Second Edition, 2008
- ISO 11171** Hydraulic Fluid Power—Calibration of Automatic Particle Counters for Liquids

3. Terminology

3.1 For definitions of terms used in this practice, refer to Terminology **D4175**.

3.2 *Definitions of Terms Specific to This Standard:*

³ Available from American National Standards Institute (ANSI), 25 W. 43rd St., 4th Floor, New York, NY 10036, <http://www.ansi.org>.

3.2.1 *bulk oil tote*, *n*—any container for lubrication or control fluid with working volume approximately 1000 L to 1300 L designed for fluid storage at atmospheric pressure.

3.2.2 *continuous sampling loop*, *n*—a limited flow of fluid from a point in a pressurized system to a point of lower pressure used to decrease required purge fluid and sample time during the sampling process.

3.2.3 *disposable sample tubing*, *n*—any single-use flexible plastic tubing used to transfer fluid during the sampling process.

3.2.4 *drain sampling*, *n*—a method of sampling used fluid for non-pressurized reservoirs or lines occurring when the lubricating fluid is being drained from the reservoir during a fluid change.

3.2.4.1 *Discussion*—As part of a fluid change, the drain plug is removed to allow the fluid to drain into an appropriate container under gravity. Mid way through the draining, a sample bottle is filled by placing it in the fluid stream and once filled immediately capped.

3.2.5 *drop tube sampling*, *n*—a method of sampling used fluid for non-pressurized reservoirs when sampling is completed by dropping an appropriate length of sampling tubing into the reservoir and using a vacuum generating device to extract the sample.

3.2.6 *permanent sample tube*, *n*—any tubing installed in a reservoir or pipe used to extract a sample from a specific location within the system.

3.2.7 *purge*, *v*—to remove the existing non-representative fluid and contaminants from the sample valve and tubing during the sampling process.

3.2.8 *remote access hose*, *n*—any permanently installed metallic or elastomeric tube or hose used to transfer fluid from the system to a point outside the system to facilitate sampling.

3.2.9 *reservoir*, *n*—any equipment-based container that holds a volume of fluid, usually under atmospheric condition, for use in the lubrication, sealing or control process.

3.2.10 *sample container*, *n*—a clean, fresh plastic bottle used for system fluid analysis (see Section 7).

3.2.11 *sample valve*, *n*—a system consisting of a male and female component used specifically for the extraction of a fluid sample either by internal system pressure or by an externally generated vacuum.

3.2.11.1 *Discussion*—The male component, referred to as a probe, may be for one time use or permanently attached to the female component, referred to as a sample valve, is used by either threading the probe onto the valve or pushing the probe into the valve for the purpose of opening the valve and allowing fluid to flow out.

3.2.12 *sample valve sampling*, *v*—to obtain a sample from either pressurized or non pressurized lines or reservoirs.

3.2.12.1 *Discussion*—When sampling non-pressurized reservoirs this sampling method usually applies a vacuum generating device and sampling tubing to extract a sample into a sampling container from a strategically located sampling valve. When sampling pressurized reservoirs or lines, this sampling

method is completed by using system pressure to force lubricating fluid into a sampling container through a sampling valve.

3.2.13 *vacuum generating device*, *n*—a pump used to create a low pressure in a sample container to cause fluid to move from a non-pressurized reservoir to the container through disposable tubing.

3.2.14 *weighted drop tube device*, *n*—a mass attached to a piece of steel or stainless steel tubing with a method to attach disposable sampling tubing to the steel or stainless steel tubing.

3.2.14.1 *Discussion*—This device is used during drop tube sampling.

4. Significance and Use

4.1 This practice is intended to assist the user, in particular the power-plant operator, to maintain effective lubrication of all parts of the turbine and guard against the onset of problems associated with oil degradation and contamination. The values of the various test parameters mentioned in this practice are purely indicative. In fact, for proper interpretation of the results, many factors, such as type of equipment, operation workload, design of the lubricating oil circuit, and top-up level, should be taken into account.

5. Properties of Turbine Oils

5.1 Most turbine oils consist of a highly refined paraffinic mineral oil compounded with oxidation and rust inhibitors. Depending upon the performance level desired, small amounts of other additives such as metal deactivators, pour depressants, extreme pressure additives, and foam suppressants can also be present. The turbine oil's primary function is to provide lubrication and cooling of bearings and gears. In some equipment designs, they also can function as a governor hydraulic fluid.

5.2 New turbine oils should exhibit good resistance to oxidation, inhibit sludge and varnish deposit formation, and provide adequate antirust, water separability, and non-foaming properties. However, these oils cannot be expected to remain unchanged during their use in the lubrication systems of turbines, as lubricating oils experience thermal and oxidative stresses which degrade the chemical composition of the oil's basestock and gradually deplete the oil's additive package. Some deterioration can be tolerated without harming the safety or efficiency of the system. Good monitoring procedures are necessary to determine when the oil properties have changed sufficiently to justify scheduling corrective actions which can be performed with little or no detriment to production schedules.

6. Operational Factors Affecting Service Life

6.1 The factors that affect the service life of turbine lubricating oils are as follows: (1) type and design of system, (2) condition of system on startup, (3) original oil quality, (4) system operating conditions, (5) contamination, (6) oil makeup rate, and (7) handling and storage.

6.1.1 *Type and Design of System*—Most modern turbine lubricating systems are similar in design, especially for the

larger units. For lubrication, the usual practice is to pressure-feed oil directly from the main oil pump. The rest of the system consists of a reservoir, oil cooler, strainer, piping and additional purification or filtration equipment, or a combination thereof. Miscellaneous control and indicating equipment completes the system.

6.1.2 *Condition of System on Start-up:*

6.1.2.1 The individual components of a lubrication system are usually delivered on-site before the system is installed. The length of on-site storage and means taken to preserve the integrity of the intended oil wetted surfaces will determine the total amount of contamination introduced during this period, the magnitude of the task of cleaning and flushing prior to use, and the detrimental effects of the contaminants. Guidance on cleaning, flushing, and purification of steam, gas, and hydro-electric turbine lubrication systems is provided in Guide **D6439** or may be sought from the equipment/lubricant supplier or other industry experts.

6.1.2.2 Turbine oil system contamination prior to startup usually consists of preservatives, paint, rust particles, and the various solids encountered during construction, which can range from dust and dirt to rags, bottles, and cans. Their effect on turbine oil systems is obvious.

6.1.2.3 Ongoing purification may be required to maintain the in-service oils at an acceptable particle cleanliness level and water content level in the case of steam turbines for reliable lubrication and control systems operation. In operational systems, the emphasis is on the removal of contaminants that may be generated due to normal oil degradation or ingressed during operation and by malfunctions that occur during operation or contaminants that are introduced during overhaul, or both.

6.1.3 *Original Oil Quality:*

6.1.3.1 Use of a high-quality oil is the best assurance of potentially long service life. Oils meeting recognized standards are generally available, and one that at least meets the requirements of the turbine manufacturer shall be used. Careful oil storage, including labeling and rotation of lubricant containers, is vital to ensure proper use and prevent degradation of the physical, chemical, and cleanliness requirements of the lubricant throughout storage and dispensing.

6.1.3.2 It is advisable to obtain typical test data from the oil supplier. Upon receipt of the first oil charge, a sample of the oil should be taken after charging the new oil and circulating (24 h) to confirm the typical test data and to use as a baseline. This baseline should act as a starting point for the physical and chemical properties of the lubricant, and for future comparisons with used oil information. This is most important! Recommended tests for new oil are given in the schedules of this practice (see **Tables 1 and 2**).

6.1.3.3 When new turbine oil is to be mixed with a charge of a different composition prior checks should be made to ensure no loss of expected properties due to incompatibility (see lubricant suppliers' specifications). These should include functional tests and checks for formation of insoluble materials. Guidance for such compatibility testing can be referenced in Practice **D7155** for evaluating compatibility of mixtures of turbine lubricating oils.

6.1.4 *System Operating Conditions:*

6.1.4.1 The most important factors affecting the anticipated service life of a given lubricating oil in a given turbine system are the operating conditions within the system. Air (oxygen), elevated operating temperatures, metals, and water (moisture) are always present to some extent in these oil systems. These elements promote oil degradation and must consequently be recorded.

6.1.4.2 Most turbine oil systems are provided with oil coolers to control temperature. In many cases, bulk oil temperatures are maintained so low, below 60 °C (140 °F), that moisture condensation can occur. Even with low bulk oil temperatures, however, there can be localized hot spots such as in bearings, at gas seals, and in throttle control mechanisms that can cause oil degradation and eventually cause system oil to show signs of deterioration.

6.1.4.3 Under the higher temperature conditions which are present in gas and steam turbines, oxidation of the oil can be accelerated by thermal-oxidative cracking leading to the production of viscous resins and deposits particularly at the point of initiation.

6.1.5 *Contamination:*

6.1.5.1 Contamination of turbine oils is often the most significant factor affecting oil service life. Contamination occurs both from outside the system and from within due to oil degradation and moisture condensation or leaks. Development of a clean turbine oil system on start-up or following maintenance is essential (following the steps in Guide **D6439**) prior to filling with the new oil. Once attained, the danger of external contamination is less but should be guarded against. The oil can be contaminated by the introduction of different type oils, which are of the wrong type or are incompatible with the system oil. The oil supplier or the turbine manufacturer, or both, should be consulted before additions are made (see Practice **D7155**).

6.1.5.2 External contamination can enter the system through bearing seals and vents. Internal contaminants are always being generated. These include water, dirt, fly ash, wear particles, insoluble particulate oil degradation products and microbial growth. From whatever source, contamination must be dealt with by monitoring oil condition and the use of purification devices such as filters, centrifuges, coalescers, and vacuum dehydrators on a regular basis. Contamination of the system oil is a valid reason to change oil or flush a unit, or both, to restore system cleanliness.

6.1.6 *Oil Makeup Rate*—The amount and frequency of makeup oil added to the system plays a very significant part in determining the life of a system oil charge. Makeup varies from below 5 % per year to as much as 30 % in extreme cases. In turbines where makeup is relatively high compared to the oil degradation rate, the degree of degradation is compensated for and long oil life can be expected. In turbines where the makeup is very low (below 5 %), a truer picture of oil degradation is obtained. However, such a system should be carefully watched since the oil life is dependent almost exclusively on its original quality. In the United States, the average makeup is typically around 7 % to 10 % per year.

TABLE 1 Minimum Sampling and Inspection Testing Schedule for New Oils

Schedule 1 New Oil-All Turbine Types		
Samples: (a) From transport or drums (b) From storage tank		
Tests	Method	Recommended Minimum Requirements for Acceptance of New Oil as Received
Viscosity	D445, D7042	Should meet Classification D2422 consistent with user purchase specifications or manufacturer's requirements.
Acid Number	D974 or D664	Acceptance limits should be consistent with user purchase specifications, new oil reference or manufacturer's requirements or a combination thereof.
Appearance	visual	clear and bright
Water Content	visual	no free water
Color	D1500	Acceptance limits should be consistent with user purchase specifications, new oil reference or manufacturer's requirements or a combination thereof.
Rust Test	D665	Required for Steam and Single Shaft combined cycle turbines. Should pass D665A for land-based turbines and D665B for marine turbines.
Oxidation Stability or Inhibition (RPVOT/Voltammetry/FTIR)	D2272, D6810, D6971	Most suitable methods and acceptance limits should be consistent with user purchase specifications, new oil reference or manufacturer's requirements or a combination thereof.
Elemental Analysis (Suggested)	D5185	Comparison with new oil reference on delivery may indicate the presence of contaminants or mislabeled oil shipment. (Other spectrochemical method may be substituted for the ICP method.)
Air Release (Suggested)	D3427	Comparison with new oil reference on delivery may indicate the presence of contaminants or mislabeled oil shipment.
Water Separation (Suggested)	D1401	Steam Turbine and Combined Cycle Systems only.
Foam (Suggested)	D892	Comparison with new oil reference on delivery may indicate the presence of contaminants or mislabeled oil shipment.

6.1.7 *Handling and Oil Storage*—Handling and dispensing methods must ensure that the quality and the cleanliness of the lubricant meet the specifications required by the equipment. Oils must be properly labeled to ensure proper selection and use. Proper stock rotation and storage methods must be considered to prevent the possible degradation of the physical and chemical properties of the lubricant during storage and dispensing.

6.2 The combination of all of the preceding operational factors for a given turbine determines its *severity level*. Each unit is different and the equilibrium operating conditions for each system must be determined in order to fix its severity level; OEM operating and maintenance specifications can also be used in setting the severity levels. The more severe a turbine system, the shorter the service life for a given oil. A useful approach to determine the severity of a turbine is given in **Appendix X1**.

7. Sampling

7.1 *General*—When taking oil samples from storage tanks or equipment in service, it is important that the extracted sample is representative and is taken from a specified loca-

tion(s) to monitor the properties of the lubricant. Correct and consistent sampling techniques are vital to achieve this. The recommended guidelines for proper sampling technique and sample handling techniques are part of Guide D8112. The user should have written standard operating procedures to ensure that samples are taken consistently according to good maintenance practices. In addition to the Guide D8112 method the following recommendations are to be considered:

7.1.1 *Microbiological Testing*—When sampling in order to perform microbiological testing, refer to Practice D7464 for guidance on sample collection and handling.

NOTE 1—For samples intended for microbiological testing, see Practice D7464. Although the guidance provided in Practice D7464 is nominally for fuel sample collection, the procedures provided are equally applicable to turbine oils.

7.2 *Sample Labeling*—A sample bottle should be properly labeled in order to track the history of a particular piece of equipment. The equipment must be identified uniquely. Labels should include the following information as appropriate:

- 7.2.1 Customer name (if appropriate),
- 7.2.2 Site (or plant name),

TABLE 2 Minimum Sampling and Inspection Testing Schedule for New Oil Charge^A

Schedule 2 Installation of a New Oil Charge		
Samples: After 24 h circulation in Turbine Retain approximately 4 L (1 gal)		
Tests	Method	Recommended minimum requirements for assessment of new oil charge
Viscosity	D445, D7042	Should meet Classification D2422 consistent with user purchase specifications or manufacturer's requirements.
Acid Number	D974 or D664	Should be consistent with user purchase specifications and new oil reference.
Appearance	visual	clear and bright
Water Content	visual	no free water
Color	D1500	Should be consistent with user purchase specifications and new oil reference.
Particle Count--Cleanliness (after filtration into equipment)	F311 or F312 or user defined	Definition of suitable cleanliness levels determined by particle count distribution depends on turbine builder and user requirements Filtration or centrifugation, or both of oil into turbine and during in-service is recommended.
Oxidation Stability or Inhibition (RPVOT/Voltammetry/FTIR) ^B	D2272, D6810, D6971	Should be consistent with user purchase specifications and new oil reference.
Elemental Analysis (Suggested)	D5185	Comparison with new oil reference on delivery may indicate the presence of contaminants or mislabeled oil shipment. (Other spectrochemical method may be substituted for the ICP method.)
Air Release (Suggested)	D3427	Comparison with new oil reference on delivery may indicate the presence of contaminants or mislabeled oil shipment.
Water Separation (Suggested)	D1401	Steam Turbine and Combined Cycle Systems only.
Foam (Suggested)	D892	Comparison with new oil reference on delivery may indicate the presence of contaminants or mislabeled oil shipment.

^A Follow recommended flushing procedures prior to installing initial fill or replacement oil charge. For general guidance, see Guide D6439.

^B Important as a baseline to determine turbine system severity. It is recommended that all tests which are performed on in-service oils for trending purposes should also be performed on a new oil charge for baseline information.

7.2.3 Location (unit number, tank number, compartment number, and so forth),

7.2.4 Turbine serial number (or other ID),

7.2.5 Turbine service hours,

7.2.6 Oil service hours,

7.2.7 Date sample taken,

7.2.8 System operating temperature and temperature of oil at sampling point,

7.2.9 Type of oil sampled (lubricant ID),

7.2.10 Sampling point/port ID,

7.2.11 Type of purification system (filters/centrifuge, and so forth), and

7.2.12 Makeup (volume) since last sample was taken.

7.3 Sampling of New Oil Deliveries:

7.3.1 A sample of the new lubricant is required to provide a baseline for the physical and chemical properties of the lubricant. Also samples taken should be representative of the oil being examined but obtained from the point(s) most indicative of gross contamination by debris and water, that is, just above the bottom of the drum or tanker compartment bottom.

7.3.2 When consignments of oil are in drums, sample them in accordance with Practice D4057.

7.3.3 For bulk consignments, sample each tanker compartment. If these are clear of debris and water, then the samples can be combined for subsequent laboratory analysis of the consignment.

7.3.4 In cases where the product is suspected of being nonuniform, sample a larger number of drums. Where contamination is suspected there is no alternative to sampling every drum.

7.3.5 From tanker deliveries, in addition to sampling individual tanker compartments, further sample(s) should be taken preferably from the outlet of the flexible pipework or at least from the tanker bottom valve manifold. This further sampling is necessary because the tanker contents can become contaminated by residual material left in the bottom valve manifold. This can occur particularly when different products are being carried in separate compartments or previous deliveries of a different product have been made to other locations without subsequent adequate cleaning and flushing.

7.3.6 Bottom samples must be collected by either a tube or thief sampler (for example, Bacon bomb). These samplers permit collection of settlings on the bottom of the container without introducing false contamination by scraping the container lining or wall.

7.3.7 Take the sample(s) from the outlet of the flexible pipework or the tanker bottom valve manifold while maintaining a good flow after flushing the line.

7.4 *Preservation of Sample and Analysis of Oil Samples*—It is generally advised to ship the oil samples immediately to the oil analysis laboratory, as ideally, oil should be analyzed as soon as reasonably achievable after being sampled. If oil samples are stored for an extended period of time, this may result in a non-representative sample.

7.4.1 If the samples are to be retained for extended periods of time, special arrangements should be made in agreement with the oil analysis laboratory to ensure that the integrity of the sample is not compromised. The special arrangement may include storing in dark amber glass bottles in an ambient temperature area as the longer an oil sample is stored in the container/bottle, the more oxidation products will be generated.

7.4.2 Store the sample(s) away from strong light and as close to room temperature as possible.

8. Examination of New Oil on Delivery

8.1 Experience has shown the need for standardizing procedures to be undertaken for the sampling, examination, and acceptance of incoming supplies of turbine oil. It is essential that personnel responsible for sampling and testing shall have the necessary experience and skills, and that scrupulous attention to detail be applied at all times to avoid erroneous results.

8.2 It is equally essential that all incoming supplies of oil be adequately monitored to guard against incorrect or contaminated material being delivered. Cleanliness of the delivery container should be noted; if the container is dirty on the outside, there may be particulate contamination on the inside. Particulate contamination can also be a problem when the lubricant comes in contact with dirty or poorly maintained equipment.

8.3 Sampling of incoming supplies should be in accordance with proper sampling procedures (see Section 7).

8.4 All samples should be immediately examined for appearance.

8.5 A testing schedule for new oil is included in this practice (see Table 1 and Table 2). With drums, tests should be completed on the bulk sample before the oil is used in service. Individual samples should be retained until the bulk sample is passed as satisfactory.

8.6 With tanker deliveries the additional tests to be completed before the tanker is discharged can only be judged from the risk involved by the acceptance of nonspecification product, that is, can the charge be readily recovered and corrected before passing into service if the subsequent tests indicate this to be necessary.

8.7 Handling and dispensing methods contribute to the required health and cleanliness specifications of the lubricant. All sources and opportunities of contamination must be avoided.

9. Deterioration of Turbine Oils in Service

9.1 *How Turbine Oils Degrade*—Irrespective of initial quality, during their use in lubrication systems of turbines,

lubricating oils will experience thermal and oxidative stresses, loss of foam control, poor oil demulsibility and loss of wear protection, which degrade the chemical composition of the oil. In order to avoid these degradation problems, lubricating oils are developed with a strong ability to control oxidation processes, degradation by wear, and other degradation mechanisms, by using a combination of good quality base oil together with a mixture of additives. For turbine oils it is very common for high quality products to have long periods of successful field operation, so that for many years the oil may perform like new. Lubricant deterioration occurs by one or more of the following processes:

9.1.1 *Oxidative Degradation*—This occurs as the result of chemical changes brought about by oxygen in the atmosphere and proceeds by a chain reaction.

9.1.2 *Thermal/Oxidative Degradation*—This degradation can occur when the oil encounters hot spots or experiences electrostatic discharges, or microdieseling in turbines. During thermal degradation at elevated temperatures, hydrocarbons may form unstable and insoluble compounds. These unstable compounds are easily oxidized and also tend to polymerize to form resins and sludge.

9.1.3 *Water Accumulation in the System*—Accumulated water promotes oil degradation as well as additive depletion, corrosion, reduced lubricating film thickness and microbial growth. It is advised to operate without the presence of free or emulsified water.

9.1.4 *Loss of Additives*—This can result in more rapid oxidation and premature rusting.

9.1.5 *Influx of Contaminants*—Contaminants arising within the system (corrosion and wear products) or from without (fly ash, dirt, and fluids) cause lubrication and wear problems.

9.2 *Properties of Oils That Must Be Retained*—In determining the condition of the system oil for continued service, the most important properties of the in-service oil are: (1) viscosity, (2) oxidation stability reserve, (3) freedom from sludge/varnish, (4) freedom from abrasive contaminants, (5) anticorrosion protection, (6) demulsibility, (7) air release, and (8) freedom from water contamination. (See Table 3.)

9.2.1 *Viscosity*—Viscosity is the most important characteristic of a turbine oil, as the oil film thickness under hydrodynamic lubrication conditions is critically dependent on the oil's viscosity characteristics. The viscosity of most commercial turbine oils are classified according to ISO (International Standards Organization) viscosity classification system. Oils fall into ISOVG32, VG46, VG68, and VG100 viscosity grades corresponding to 32 cSt, 46 cSt, 68 cSt, and 100 cSt at 40 °C and to approximately 165 SUS, 240 SUS, 350 SUS, and 515 SUS at 100 °F (Classification D2422). The main purpose for checking the viscosity of used turbine oil is to determine if the correct oil is being used and to detect contamination. Used turbine oils rarely show significant viscosity changes due to degradation. Occasionally, viscosity increases due to an emulsion with water contamination. The method normally used for viscosity determinations is Test Method D445 or D7042.

9.2.2 *Oxidation Inhibitor*—The monitoring of antioxidant concentration is important for controlling the oxidation of industrial lubricants and their remaining useful life. Some

TABLE 3 Visual Inspection of In-service Oil Samples^A

NOTE 1—For consistency, the following are suggested: (1) visual inspections be performed after a 5 min settling time, (2) use of clear sample containers, and (3) use of focused lighting to enhance visual observations.

Appearance of Oil just after Sampling	Appearance of Oil after 1 h Settling ^B	Possible Cause	Action Steps
Clear	Clear
Foam at the Surface	Foam collapsed	Air entry likely of mechanical origin or from sampling process	Investigate cause
	Stable persistent foam	High foaming tendency- Possibly contamination or antifoam depletion.	Investigate cause and conduct laboratory control test for foam
Sample contains small air bubbles at sampling then becomes clear from the bottom	Clear	Aeration if bubbles persist for more than 5 min.	Investigate cause
	Persistent entrained small air bubbles	High air entrainment- Possibly contamination, oil degradation	Investigate cause and conduct laboratory control test for air release
Sample cloudy and becoming clear from the top	Clear or slightly opaque, decanted free water	Unstable water emulsion	Determine source of water ingress
	Hazy	Presence of soft contaminants and insolubles	Determine possible presence of varnish contaminants
	Milky	Stable water emulsion	Investigate cause and conduct laboratory control test for water separation
Dirty	Presence of decanted solid particles	Contamination, possible filtration problem	Investigate cause and re-filter
Strange color, rapid and unusual darkening	...	Contamination or excessive degradation	Investigate cause and conduct laboratory control test for oxidation
	Acrid	Oil cracking due to overheating	Investigate cause. Check Viscosity, Acid No, Flash point
Unusual odor	Putrid or rancid	Growth of bacteria or fungi	Check for presence of water. Withdraw the separated water. Test for microbial contamination and consult with oil supplier regarding biocide treat
	Rotten eggs	Growth of anaerobic Sulfate Reducing Bacteria	

^A These visual screening tests can be performed on site by the turbine unit operator.

^B A complete reference to visual inspection definitions can be found in [D7155](#).

practices for measuring the concentration of phenolic (or amine) antioxidants include infrared spectrometry (including Fourier Transform Infrared) and voltammetry. When setting up one of these techniques, it is advisable to consult with the lubricant supplier who has a working knowledge of the antioxidants used in the turbine oil formulation.

9.2.2.1 FTIR—The Fourier Transform Infrared (FTIR) practice is a refined infrared spectroscopy method, which can be used to monitor change in the availability of the original antioxidants blended into the oil. It can also be used to monitor the change in oxidation products as the oil degrades. Each oil will produce a unique spectrum and a baseline must be established to obtain benefit from this technique. Each antioxidant is a specific chemical substance and will absorb infrared light at a particular wavelengths and absorptivities; some antioxidants may not be detectable by infrared spectroscopy. (Test Method [D2668](#) may be used for antioxidants if the wavelengths and absorptivities are known and in the case the lubricant contains no antioxidant other than 2,6-di-*t*-butyl-*p*-cresol or 2,6-di-*t*-butylphenol.)

9.2.2.2 Voltammetry—Voltammetry is an electrochemical test technique, which can be used for measuring primary antioxidant additives. The technique applies a voltage ramp through a three electrode sensing system and measures the current flow that occurs when the applied voltage equals the oxidation potential of the antioxidant. The potential of the produced voltammetric peak aids in the identification of the antioxidant and the height of the produced peak is proportional to the concentration of the antioxidant. Antioxidants such as phenols (in accordance with Test Method [D6810](#) and [D6971](#)),

amines, and ZDDP can be measured. A product type baseline must be available for use as a comparison to report a change.

9.2.3 Oxidation Stability Reserve:

9.2.3.1 One of the important properties of new turbine oil is its oxidation stability. Traditionally, this has been measured by Test Method [D943](#) with Test Method [D2272](#) being used as an ancillary (rapid) method for following changes of oil condition in service. Oxidation stability will gradually decrease in service, deterioration being promoted by the catalytic effects of metals in the system (iron and copper) as well as by the depletion of the antioxidant. The latter occurs as a result of the normal function of the additive (chemically it acts as a chain-stopper in controlling oxidation), or by volatilization. As the oxidation stability reserve decreases, acidic compounds are produced which in turn undergo further reactions to form more complex compounds. The end products of these processes are insoluble sludge and lacquering. Although only a minute fraction of the oil is converted in this way, sufficient sludge and lacquering can form to settle in critical areas of the system, leading to filter blockage, interference with proper lubrication and cooling of bearings and moving parts.

9.2.3.2 The test method to detect severe oxidative degradation is the acid number (Test Methods [D664](#) and [D974](#)). Most rust inhibitors used in turbine oils are acidic and contribute to the acid number of the new oil. An increase in acid number above the value for new oil indicates the presence of acidic oxidation products, microbial growth in the system or, less likely, contamination with acidic substances. An accurate determination of the acid number is very important. However, this test does not measure oxidation stability reserve, which is

better determined by Test Method **D2272**. This latter test is included in the recommended testing schedules (see **Table 1** and **Table 2**).

9.2.4 *Freedom from Sludge/Varnish:*

9.2.4.1 Due to the nature of the highly refined lubricant basestocks used in the manufacture of turbine oils, they are very poor solvents for sludge/varnish. This is the main reason why the oxidation stability reserve of the oil must be carefully monitored. Only a relatively small degree of oxidation can be permitted, otherwise there is considerable risk of sludge/varnish deposition in bearing housings, seals, gears, and pistons.

9.2.4.2 Measurement of the amounts of sludge/varnish as insoluble, soft contaminants (coloured bodies) in turbine oils (Test Method **D7843**) is possible. Sludge/varnish already laid down within the system would not be included in such a determination. Other tests, however, can signal deteriorating quality in the oil even before any significant formation of sludge/varnish occurs.

9.2.4.3 Filtration and centrifugation assist in removing sludge/varnish from the oil as it is formed but cannot protect the system if the oil is allowed to deteriorate too far before an oil change.

9.2.5 *Particle Counting:*

9.2.5.1 The most deleterious solid contaminants found in turbine oil systems are those left behind when the system is constructed and installed or when it is opened for maintenance and repair. The need for proper cleaning and flushing of new or repaired turbine systems is emphasized. Beyond these types of contaminants, there are few opportunities for solids to enter the lube oil system, although in very dusty areas where units may be out-of-doors, some solids can enter through improperly installed or operating vents.

9.2.5.2 During operation, the equipment begins to accumulate significant amounts of particulates. Some may enter the system through the makeup oil when it is added. Fly ash may be drawn in with the air at bearing shaft seals. Other contaminants may be abrasive degradation and corrosion products developed in the system. Whatever the source, the presence of abrasive solids in the oil cannot be tolerated since they will promote scoring and damage to bearings and journals as well as causing malfunction and sticking of control mechanisms. These must be removed by the use of filters or centrifuge, or both. When the amount of makeup is low and the various filters and purifiers are operating satisfactorily, abrasive solids are generally removed before any damage is done. In a properly maintained system the particulate level presents no problem. Cleanliness of the system oil can be determined by gravimetric means (Practice **F311** or Methods **F312**) or by particle counting (Test Method **D7647**), the latter normally by means of electronic particle counters. Cleanliness levels can be represented by classification systems such as ISO 4406:1999. ISO 4406:1999 uses a numeric code to reference the number of particles larger than 4 μm , 6 μm , and 14 $\mu\text{m}/\text{mL}$ of oil. ISO 4406:1999 assigns integer values to denote a range of particles whose upper limit doubles with each successive number. Desired cleanliness levels are sometimes designated by the equipment manufacturer or user. If a cleanliness level is not

specified by the manufacturer, cleanliness in the range from ISO – 16/14/11 to – 18/16/13 (ISO 4406:1999) is usually considered satisfactory.

9.2.6 *Rust Protection:*

9.2.6.1 Rust protection provided by the lubricant is of significant importance for turbine systems. Protection is required in areas of fluid flow, for surfaces covered by static drops of water and for areas which are only occasionally splashed by the lubricant. New oil usually contains a rust inhibitor additive and must meet test requirements such as Test Method **D665**. In service, this additive can become depleted by (1) performing its proper function, (2) by removal with water, (3) by adsorption on wear particles and other solid debris, or (4) by chemical reaction with contaminants. In exceptional circumstances where alkaline or polluted water enters the system, additive removal will be much more rapid. Test Method **D665** Procedure A (distilled water rust test) is adequate for determining a satisfactory level of antirust inhibitor for land-based turbines. For marine usage, Test Method **D665** Procedure B (seawater rust test) is recommended.

9.2.6.2 Although rusting is the most important corrosive tendency to guard against, the possibility exists of other types of corrosion brought about by active sulfur or strong acids. Generally, these factors are of little significance for turbines since new oils must meet very strict requirements in this regard and used oils are normally discarded before any corrosive breakdown products are formed. Contamination is the most likely factor if the used oil does not continue to meet new oil standards for copper strip corrosion (see Test Method **D130**).

9.2.7 *Water Separability:*

9.2.7.1 Water can get into turbine systems due to oil cooler leaks, normal breathing, and gland seal steam. Water adversely affects turbine oils by acting with metals to catalyze oxidation. It also depletes water-sensitive oil additives such as some types of turbine oil rust inhibitors, and can cause rusting and corrosion and can promote microbial growth. In gas turbines, minor amounts of water are driven off during normal operations. In steam turbines, normally if the oil is in good condition, water will settle to the bottom of the storage tank, where it should be drained off as a routine operating procedure. Purification systems will also assist in removing the water. Unfortunately if the steam turbine oil has developed poor water separability properties (as measured by Test Method **D1401**) significant amounts of water will stay in the system and create problems. In addition to chemical effects on the oil and additives, the lubricating properties of the oil can be adversely affected; adequate lubrication cannot be maintained by an oil which contains a significant quantity of water. Therefore, lubricant flow to bearings should not contain significant amounts of free or dispersed water. There are considerable differences of opinion as to what level of water is harmful, but 0.1 % is generally considered significant.

9.2.7.2 If an oil is clear and bright, the amount of dissolved water present is of little significance. Most turbine oils will remain clear with up to 100 ppm of water at room temperature.

9.3 *Other Properties of Used Oils*—There are various other properties of used turbine oil which can be measured but are considered of less significance. These are discussed as follows:

9.3.1 Color—New turbine oils are normally light in color. Some turbine oils darken on exposure to sunlight or U/V light. This is not abnormal. Darkening will occur in service but the change is usually slow over years of service. Frequent checks for color are therefore useful as a quick on-the-spot test. A significant color change would be indicative that unusual and rapid darkening can be a direct result from contamination or excessive degradation. A more detailed examination would be necessary to find the cause. Test Method **D1500** is the standard method for defining the color of lubricants. Color darkening alone is not itself a cause for alarm (unless supported by additional tests).

9.3.2 Flash Point—Turbine oils, like most lubricants, must have flash points well above the minimum applicable safety requirements. However, flash point is of little significance for determining the degree of degradation of used oils, since normal degradation has little effect on the flash point. It is useful for detecting contamination with low-boiling solvents. The method in common use is Test Method **D92** (Cleveland Open Cup).

9.3.3 Foaming Characteristics—Foaming characteristics are measured by Test Method **D892** which indicates both the tendency of the oil to foam and the stability of the foam after it is generated. This test may be useful in troubleshooting oil foaming problems in equipment. Some increase in foaming tendency over time will occur due to changes in the oil's surface tension resulting from normal oil degradation, trace contamination and this increase in foaming tendency is often observed and may not be of a concern (see **Table 3**). System foaming problems have three possible origins.

9.3.3.1 Mechanical—The system design can have a major impact on the foaming tendency of a lubricant.

9.3.3.2 Antifoam Additive Depletion—Antifoam agents may be removed mechanically (due to fine filtration, centrifuging, mechanical shearing, or adsorption) because they are dispersed and not dissolved in the oil. Caution must be practiced not to overdose with additional defoamant as this may have a detrimental impact on air release properties of the oil.

9.3.3.3 Contamination—An attempt should be made to identify and remove the contaminants. In cases where this cannot be done adequately, this may be corrected with an addition of defoamant.

9.3.3.4 Air Release Properties—Agitation of lubricating oil with air in equipment such as bearings, couplings, gears, pumps, and oil return lines may produce a dispersion of finely divided air bubbles in the oil. If the residence time in the reservoir is too short to allow the air bubbles to rise to the oil surface, a mixture of air and oil will circulate through the lubricating oil system. This may result in an inability to maintain oil pressure (particularly with centrifugal pumps), incomplete oil films in bearings and gears, and poor hydraulic system performance or failure. The time required for air entrained in the oil (in Test Method **D3427**) to reduce in volume to 0.2 % is recorded as the air bubble separation time.

9.3.4 Elemental Analysis—Emission spectroscopy can be used to analyze for elements found in used lubricating oil. This analysis is generally limited to dissolved materials or particles

smaller than about 8 μm (see Practice **D5185**). The elements found derive from wear debris, additives, and contamination.

9.3.4.1 Some wear on metal parts can be considered to be normal (although not desirable). Large amounts of metal contaminants usually indicate a serious machine problem. Since different machine parts are made from different metals, the presence of particular metals indicate which components are wearing. When a machine has been sampled several times (or when multiple machines of the same type have been tested), an evaluation is made to determine whether the metal concentrations are outside of the normal range. Samples from a piece of equipment that have metal concentrations increasing at an unusually high rate or outside of the normal range indicate that the equipment may have a problem. When no historical data is available, there is a chance that not enough significance will be given to a particular wear metal and its concentration.

9.3.4.2 Certain elements which are found as lubricant oil additives can also be analyzed to ensure that the appropriate additives are present and that there are no other inorganic additives which indicate that cross-contamination has occurred. An analysis should be performed on unused oil in order to establish a baseline for future comparisons.

9.3.4.3 Contaminants (such as dirt and water) in the oil can be carried throughout the machine and cause severe wear or corrosion. The presence of dirt can be detected by the presence of silicon (or aluminum). Inorganic constituents of fresh and treated water may be detected using elemental analysis. Examples of these may be: calcium from untreated water, sodium and magnesium from sea water, and potassium, sodium or boron from cooling water. (See **Table 4**.)

9.4 Microbiological Contamination—If contamination with water occurs, microbial growth can occur in oils in service and in storage. The microbes can grow in water accumulated at system low points and in water droplets suspended in the oil. They feed on and degrade the base oils and additives, accelerating oxidative and hydrolytic processes. The slime (biomass) formed by the microbes can block filters, oil lines and system orifices. Microbially generated acids cause increase in AN and can lead to severe system corrosion. The oil formulation may provide all of the necessary nutrients for microbial growth although sometimes nutrients are supplemented by the contaminating water. Microbial growth will generally only occur when and where temperature is below 50 °C and, thus, it is primarily a risk in medium and low temperature systems or during prolonged system outage or oil storage.

9.4.1 Depending on the method employed, particle counts and tests for acid number may highlight the possibility of microbial contamination in the oil system. Further investigation by microbiological testing may be warranted. Where temperatures are conducive to microbial growth and where there is a known issue of water accumulation, routine microbial testing is recommended.

9.4.2 There are currently no designated standard methods for microbiological testing of oils. The microbiological method employed should be appropriate for testing viscous, non-aqueous samples. Two methods which have been demonstrated to be suitable for testing oils in the field or the laboratory are Test Methods **D7687** and **D7978**; both these methods are

TABLE 4 Sources of Potential Inorganic Elemental Contaminants in Oil

Element/Symbol	Wear Metal	Additive	Contaminant	Primary Sources	Secondary Sources
Aluminum/Al	X		X	pistons, journal bearings, blowers, turbo charge vans, torque converters, pump vanes	dirt, alloy with copper, in rolling element bearings cages, housings and cases
Antimony/Sb	X	X	X	journal bearings	grease, anti-scurf additive
Barium/Ba		X		additive ^A	grease
Boron/B		X	X	additive ^A , treated coolant water	few
Cadmium/Cd	X			journal bearings	plating
Calcium/Ca		X	X	additive ^A	water, grease
Chromium/Cr	X			compression rings, chrome cylinders	alloyed with iron found in rolling element bearings, shafts found in hard steels
Copper/Cu	X	X		bearings, cages, bushings, thrusts, valve guides, oil coolers, bearing cages, pumps	automotive lubricant additives
Iron/Fe	X		X	cylinders, shafts, gears, rolling elements bearings, housings, cases. for EHC fluid, some acid scavenging filters may contribute this wear metal to the fluid	rust, fretting corrosion
Lead/Pb	X		X	journal bearings, main bearings, platings, pumps	paint, solder, seals
Magnesium/Mg		X		additive ^A	sea water
Manganese/Mn	X			shafts, valves, blowers	few
Molybdenum/Mo	X	X		additive ^A , for EHC fluid, some acid scavenging filters may contribute this wear metal to the fluid	compression rings
Nickel/Ni	X			alloyed with iron for hard steel shafts, rolling element bearings	few
Phosphorus/P	X	X		additive ^A , for EHC fluids, this is the primary component	surface finish for gears
Potassium/K			X	coolant additive	few
Silicon/Si	X	X	X	sand, dirt, dust, antifoam additive for EHC fluid, some acid scavenging filters may contribute this wear metal to the fluid	alloyed with iron (cast iron)
Silver/Ag	X			wrist pins (EMD), flashing	solder
Sodium/Na		X	X	found in some new oils, cooling additive	sea water, grease
Tin/Sn	X			journal bearings, alloyed with copper in rolling element bearing cages, flashing	solder
Titanium/Ti	X			turbine blades	paint, esterification catalyst in ester-based oils
Vanadium/V	X			turbine blades	valves
Zinc/Zn		X	X	additive ^A	galvanized steel, platings, grease

^A The elements whose primary source is shown as “additive” are used as possible additives in oils, but are not supposed to be in the turbine oil. P can be found if the turbine oil is of the EP type and, for this element, if it was found in the new shipment of the oil or the initial in-service oil sample taken in 6.1.3.2, or both, and the amount is comparable to either of these, this can be reported as normal.

designated for testing fuels and associated contaminating water and although they can be utilized to test oils, this is outside their respective scopes.

9.4.2.1 Test Method **D7687** measures the concentration of cellular- Adenosine triphosphate (ATP) present in the sample. ATP is a constituent of all living cells, including bacteria and fungi. Consequently, the presence of cellular-ATP is an indicator of total metabolically active microbial contamination. Test Method **D7687** can be used for oils using the procedure described for fuels.

9.4.2.2 Test Method **D7978** measures culturable, viable aerobic microbial content present in the form of bacteria, fungi, or their spores, or combinations thereof. Test Method **D7978** can be used for oils using the procedure described for testing heavy and residual fuels.

9.4.2.3 In some cases additional tests for specific types of microbes may be warranted, for example for sulfate reducing bacteria (SRB) which generate sulfide and can cause rapid and severe corrosion.

10. Monitoring Program

10.1 A sound monitoring program is based on four factors: (1) obtaining representative samples and testing at appropriate

intervals; (2) logging, trending, and interpretation of test data; (3) action steps; and (4) insurance of maintenance follow-up.

10.1.1 The application of the ASTM standards for trending (Guide **D7669**) and for evaluating limits (Guide **D7720**) is an advisable approach for long term fluid condition monitoring.

10.2 *Sampling and Testing of Oil Samples*—Schedules for routine monitoring should be tailored to the individual facility depending on the criticality and severity of usage of the turbines. The schedules included in **Table 1** (for steam turbines) and **Table 2** (for gas turbines) are typical and should only be used as a guide. Refer to the OEM (original equipment manufacturer) instructions or other regulatory guidelines for lubricant testing requirements. In addition to the tests in **Tables 1 and 2**, any deposits found in the oil or removed from the system should be examined and identified (if possible).

10.3 *Logging, Trending, and Interpretation of Test Data*—It is important to keep accurate records of test results and makeup. Graphical representations are highly recommended for key parameters such as acid number, oxidation inhibitor, wear particle concentration, wear metals, and RPVOT. In this way, unusual trends become apparent and better estimates made of remaining service life. Interpretation of test data

should take into account such factors as oil addition (make-up or replacement oil), possible intermixing of oils, newly installed parts, and recent system inspections. Guidelines for warning levels are provided for various lubricant types in **Tables 5-7**. Oil supplier guidelines or original equipment manufacturer (OEM) guidelines, or both, supersede **Tables 5-7**. These warning levels should also be considered with trending information.

10.4 Action Steps—The main purpose of a monitoring program is to ensure long trouble-free operation of the equipment. This can only be achieved by prompt and proper action steps when necessary. Such action steps must be based on a correct interpretation of test results (see **Tables 5-7**), usually gathered over a period of time. Corrective action should generally never be taken on the basis of one test result since it may be incorrect due to poor sampling or faulty testing. Resampling and retesting is recommended before proceeding. Actions recommended by the oil supplier or the original equipment manufacturer, or both, supersede those in **Tables 5-7**.

10.5 Maintenance Follow-Up—When maintenance is performed on equipment included in the oil monitoring program, the records of work performed and problems found should be documented and made available to those responsible for interpreting the oil test data. In this way, the test data interpreter can (1) ensure that recommended maintenance was performed, (2) make better recommendations, and (3) learn better how test data correlate with equipment problems.

11. Sludge and Deposits

11.1 The accumulation of sludge or deposits in any part of a turbine system is cause for concern. During outages, inspection should be made of all accessible parts of the system, in particular the reservoir, turning gear, regulating valves and so forth. Varnishing usually results when soft contaminants that have been formed by oil oxidation and degradation deposit on various surfaces. When these deposits form on critical components, damage can occur up to, and including equipment failure. Samples of the deposits should be taken for analysis. During operation, any unusual amount of solids removed during centrifugation or filtration should be noted. An initial examination of any deposit can be made very simply. For this, a small amount of the deposit is washed free of oil with a petroleum solvent from a squeeze bottle. After drying, a small magnet can be used to separate iron-derived matter. Examination with a simple 10-power pocket magnifying glass will often

help to decide the nature and source of the debris. If necessary, the deposit can be sent to a well-equipped laboratory for full identification. If significant amounts of sludge or varnish, arising from oil oxidation, are found in the system, action should be taken to clean out the system and replace the oil charge. If the deposit consists essentially of contaminant material such as fly ash or other debris, appropriate action is necessary to remedy the cause.

12. Test Schedules

12.1 Steam (Table 5) and Gas (Table 6) and Single Shaft Combined Cycle (Table 7) Turbines—Mineral Oils:

12.1.1 The following test schedules are based mainly on tests that can be run by most power station laboratories. An important exception is probably the RPVOT to determine remaining service life where the assistance of an outside laboratory or the oil supplier may be necessary.

12.1.2 New oil should be sampled and tested for agreement with quality requirements as it is received. Upon the installation of a new oil charge, either as an initial fill or as replacement charge, an approximately 4 L (1 gal) sample should be taken after 24 h circulation. This is a most important sample since it is used as the baseline for comparison with later test data. The sample should be retained for at least 12 months. Significant differences in quality between the new oil (as received) and the 24 h sample should be investigated. A check sample is sometimes necessary. Contaminants in the system and residues from degraded oil can adversely affect the potential service life of the new oil charge. The purpose of the initial schedules, 12 months for steam turbines and 4 months to 6 months for gas turbines, is to determine the severity of service. For this, fairly frequent sampling and testing is required. The amount of degradation occurring during this initial period serves as a guide to establish future sampling frequency.

12.1.3 The normal test schedules are for systems which normally expect a long service life. The history of the present charge or the results of the first 6 months to 12 months testing of a replacement charge is usually sufficient to determine if the normal schedule will apply. Eventually, as test results indicate that the oil is becoming degraded and may be approaching the end of its service life, the sampling frequency should be increased.

13. Keywords

13.1 gas turbines; in-service monitoring; mineral; mineral turbine oil; monitoring program; steam turbines; turbine oil

TABLE 5 Steam Turbine Test Schedule, Interpretation and Recommended Action Steps

NOTE 1—Frequency (New Turbine Installation First 12 Months)—Suggested sample frequency is every 1 month to 3 months or as agreed upon with lubricant or condition monitoring provider. Normal Operation is every 4 months to 6 months or as agreed with lubricant or condition monitoring provider. The sample frequency should be used as a guide. Increased frequency (half the suggested time intervals) is recommended for a severe turbine or for oils approaching the end of their service life. Most turbines should be covered by this schedule. Sample frequency is based on continuous operation or total accumulated service time.

NOTE 2—For combined cycle systems where the gas turbine (see [Table 6](#)) and steam turbines (see [Table 5](#)) have separate lubricating circuits follow the test schedules for the individual turbine type.

Test	Method	Warning Limits ^a	Interpretation	Action Steps
Viscosity	D445, D7042	± 5 % of new oil, max Up to 20 000 h: $\Delta > (0.10 \text{ mg KOH/g}) / \text{year}$	(1) Oil is contaminated, (2) oil is severely degraded, or (3) high or low viscosity fluid added This represents abnormal deterioration. Possible causes are: (1) system conditions are severe and promote abnormal oil deterioration, (2) primary antioxidant depleted, (3) wrong makeup oil used, (4) contamination	Determine cause. If viscosity is low determine flash point. Change oil, if necessary. Investigate cause, increase frequency of testing—Compare with RPVOT, MPC, Voltammetry, or FTIR data, or combinations thereof. Consult with Oil Supplier for possible remedy.
Acid Number	D974 or D664	More than 20 000 h: $\Delta > (0.15 \text{ mg KOH/g}) / \text{year}$	This represents severe deterioration. The oil is at or near the end of service life. Possible causes are: (1) system conditions (temperature etc.) are severe and promote severe oil deterioration, (2) primary antioxidant depleted, (3) or (4) above may apply	Look for signs of increased sediment on filters and centrifuge. Check RPVOT, MPC, Voltammetry, or FTIR data, or combinations thereof. If RPVOT or antioxidant level is less than 25 % of original, review status with oil supplier and consider oil change. Increase test frequency if left in system.
Appearance	Visual	hazy	Oil contains water, entrained air or solids or a combination thereof. See also Table 3 .	Investigate cause (see Table 3) and remedy, check water content or air release. Filter or centrifuge oil, or both. Check for other potential source of contamination, if needed.
Water Content	D6304	exceeds 0.02 % or 200 mg/kg	Oil contaminated. Potential water or steam leak.	Investigate and remedy cause. Remove water by centrifugation, coalescence or vacuum dehydration as appropriate. If still unsatisfactory, consider oil change or consult oil supplier.
Color	D1500	unusual or rapid darkening	This may indicate (1) contaminations, or (2) excessive degradation	Determine cause and rectify. Consider oil change
Particle Count—Cleanliness	F311 and F312 or D7647 or User defined	18/16/13 or OEM recommended limits	Source of particulates may be: (1) makeup oil, (2) dust or ash entering system, (3) wear condition in system, (4) preservatives from turbine replacement part (5) soft contaminants due to oil degradation	Locate and eliminate source of particulates. Check oil for insolubles and wear metals. Clean system oil by filtration or centrifuging, or both.
Wear Metals	D5185	greater than 10 ppm to 20 ppm	Indicates the presence of wear conditions or contamination. (See Table 4 .)	Perform wear debris analysis
Additive Elements	D5185	± 25 % of the new oil	Additive depletion, wrong oil added, oil dilution, or additive precipitation/dropout	Consult with oil supplier regarding situation. Check for dilution with another oil or fluid. Check other quality parameters. Consider oil change
MPC—varnish test	D7843	20 dE—increased amount of varnish may need attention 30-dE—cautionary limit requiring corrective actions Up to 20 000 h: less than 50 % or greater than 25 % of original value	Source of insoluble color bodies may be soft contaminants due to oil degradation (1) Above normal degradation, (2) Higher than new oil RPVOT may result from addition of new oil or test interferences from antioxidant intermediates	Locate and eliminate source of contaminants. Clean system oil by adequate filtration techniques
RPVOT ^b	D2272	More than 20 000 h: less than 25 % of original value	Together with high acid number, indicates oil at or approaching end of service life	Investigate cause. Check turbine system for possible signs of sludge or deposit formation. Check Insolubles. Compare with other data indicating of oxidation degradation. Increase frequency of testing. (If results are erratic, consider alternate test for monitoring oxidation inhibition.) Resample and retest. If same, consider oil change

TABLE 5 Continued

Test	Method	Warning Limits ^A	Interpretation	Action Steps
Voltammetry/FTIR ^B (Antioxidant Trending)		Up to 20 000 h: less than 50 % total RUL	(1) Above normal degradation. Note: If Voltammetry results exceeds new oil value, check for peak shifting, new peak formation or test probe contamination	Investigate cause. Check turbine system for possible signs of sludge or deposit formation. Check Insolubles. Compare with other data indicating of oxidation degradation. Increase frequency of testing. (If results are erratic, consider alternate test for monitoring oxidation inhibition.)
	D6810 , D6971	More than 20 000 h: less than 25 % total RUL compared to original value For multiple antioxidants, less than 25 % of the final remaining primary antioxidant peak Up to 20 000 h: Light fail	Together with high acid number, indicates oil at or approaching end of service life	Resample and retest. If same, consider oil change
Rust Test, Procedure A	D665	Up to 20 000 h: Light fail	(1) The system is wet or dirty or both (2) The system is not maintained properly (for example, water drainage neglected, water removal equipment malfunctioning)	Investigate cause and make necessary maintenance and operating changes. Recheck Rust Test, consult with oil supplier regarding possible remedy if test result unchanged
Insolubles	D2273	More than 20 000 h: Light fail greater than 0.1 wt %	Normal additive depletion in wet system Indicates (1) contamination of oil by equipment wear or other debris, or (2) oil or additive degradation	Consult oil supplier regarding rejuvenation by bleed and feed Investigate cause. Filter or Centrifuge oil, or both. Consider oil change
Water Separability at 54°C ^C	D1401	greater than 3 mL stable emulsion or less than 36 mL water at 60 min, or both	Possibly pollution, contamination, degradation	Compare with other test data indicating degree of degradation. Locate and eliminate source of contaminants. Clean system by adequate filtration techniques. Consider oil change if water separability can not be restored.
Foaming Test, Sequence 1 ^C	D892	exceeds following limits: tendency 450 mL and stability 10 mL	Possibly contamination or antifoam depletion. In new turbines, residual rust preventives absorbed by oil may cause problem	High tendency data should be confirmed by reservoir visual inspection. Rectify cause. Check with oil supplier regarding filtration and oil rejuvenation by bleed and feed
Air Release ^C	D3427	exceeds following limits: double the time compared to new oil	Possibly contamination or excess antifoam re-addition. In new turbines, residual rust preventives absorbed by oil may cause problem	Watch the system as required. Rectify cause. Compare with other results. Consider rejuvenating with bleed and feed
Flash Point ^C	D92	Drop 15 °C or more compared to new oil	Probably contamination	Determine cause. Check other quality parameters. Consider oil change
Microbial contamination ^D	D7978 or D7687	10 fold increase above established norms	Microbial growth is occurring with potential for filter plugging, system fouling, oil degradation and corrosion. Water ingress or accumulation is occurring.	Identify source of water and make necessary maintenance or operational changes. Use filters or centrifuges, or both, to remove microbial contamination and water. In severe cases flushing or biocide treatment, or both, may be needed

^A Warning limits apply at any time unless otherwise stated.

^B Consult with oil supplier regarding most appropriate methods, which may be RPVOT, Voltammetry, or FTIR or a combination thereof.

^C If contamination is suspected, additional tests such as Flash Point, Foam, Water Separability, Rust and Air Release, may be useful to determine degree and effect of contaminants present. An outside supplier or oil supplier can also assist in a more in-depth analysis.

^D Microbes are ubiquitous in many environments and there are no universally accepted limits for microbial contamination in oils. The levels of contamination which can be tolerated will depend on the system and the type of microbial contamination. Microbes will generally be far more numerous in low point samples and samples containing water. For routine microbiological monitoring, baseline contamination levels should be established for designated sample points, which should include a system low point and a representative sample of circulating oil (before any filters or centrifuges). A ten-fold increase in microbial counts should highlight that microbial growth may be occurring. Typically, microbial counts of over 1 000 microbes/mL of oil in low point samples or over 100 microbes/mL in representative samples of circulating oil indicate contamination levels are above normal background level. Counts ten times these levels could indicate a potential for microbially related operational problems.



TABLE 6 Gas Turbine Test Schedule, Interpretation and Recommended Action Steps

NOTE 1—*Frequency (New Turbine Installation First 12 Months)*—Suggested sample frequency is every 1 month to 3 months or as agreed upon with lubricant or condition monitoring provider. Normal Operation is every 4 months to 6 months or as agreed with lubricant or condition monitoring provider. The sample frequency should be used as a guide. Increased frequency (half the suggested time intervals) is recommended for a severe turbine or for oils approaching the end of their service life. Most turbines should be covered by this schedule. Sample frequency is based on continuous operation or total accumulated service time.

NOTE 2—For combined cycle systems where the gas turbine (see Table 6) and steam turbines (see Table 5) have separate lubricating circuits follow the test schedules for the individual turbine type.

Test	Method	Warning Limits ^a	Interpretation	Action Steps
Viscosity	D445, D7042	± 5 % of new oil, max Up to 20 000 h: $\Delta > (0.10 \text{ mg KOH/g}) / \text{year}$	(1) Oil is contaminated, (2) oil is severely degraded, or (3) high or low viscosity fluid added This represents abnormal deterioration. Possible causes are: (1) system conditions (temperature etc.) are severe and promote abnormal oil deterioration, (2) primary antioxidant depleted, (3) wrong makeup oil used, (4) contamination	Determine cause. If viscosity is low determine flash point. Change oil, if necessary. Investigate cause. Increase frequency of testing—Compare with RPVOT, MPC, Voltammetry, or FTIR data, or combinations thereof. Consult with Oil Supplier for possible remedy.
Acid Number	D974 or D664	More than 20 000 h: $\Delta > (0.15 \text{ mg KOH/g}) / \text{year}$	This represents severe deterioration. The oil is at or near the end of its service life. Possible causes are: (1) system conditions (temperature etc.) are severe and promote severe oil deterioration, (2) primary antioxidant depleted (3) or (4) above may apply	Look for signs of increased sediment on filters and centrifuge. Check RPVOT, MPC, Voltammetry, or FTIR data, or combinations thereof. If RPVOT or antioxidant level is less than 25 % of original, review status with oil supplier and consider oil change. Increase test frequency if left in system.
Appearance	Visual	hazy	Oil contains water, entrained air or solids or a combination thereof. See also Table 3.	Investigate cause (see Table 3) and remedy, check water content or air release. Filter or centrifuge oil, or both. Check for other potential source of contamination, if needed.
Color	D1500	unusual or rapid darkening	This may indicate (1) contaminations, or (2) excessive degradation	Determine cause and rectify. Consider oil change
Particle Count—Cleanliness	F311 and F312 or D7647 or User defined	18/16/13 or OEM recommended limits	Source of particulates may be: (1) makeup oil, (2) dust or ash entering system, (3) wear condition in system, (4) preservatives from turbine replacement part (5) soft contaminants due to oil degradation	Locate and eliminate source of particulates. Check oil for insolubles and wear metals. Clean system oil by filtration or centrifuging, or both.
Wear Metals	D5185	greater than 10 ppm to 20 ppm	Indicates the presence of wear conditions or contamination. See Table 4.	Perform wear debris analysis
Additive Elements	D5185	± 25 % of the new oil	Additive depletion, wrong oil added, oil dilution, or additive precipitation/dropout	Consult with oil supplier regarding situation. Check for dilution with another oil or fluid. Check other quality parameters. Consider oil change
MPC—varnish test	D7843	20 dE—increased amount of varnish may need attention 30-dE—cautionary limit requiring corrective actions	Source of insoluble color bodies may be soft contaminants due to oil degradation	Locate and eliminate source of contaminants. Clean system oil by adequate filtration techniques
RPVOT ^b	D2272	Up to 20 000 h: less than 50 % or greater than 25 % of original value More than 20 000 h: less than 25 % of original value	(1) Above normal degradation, (2) Higher than new oil RPVOT may result from addition of new oil or test interferences from antioxidant intermediates Together with high acid number, indicates oil at or approaching end of service life	Investigate cause. Check turbine system for possible signs of sludge or deposit formation. Check Insolubles. Compare with other data indicating of oxidation degradation. Increase frequency of testing. (If results are erratic, consider alternate test for monitoring oxidation inhibition.) Resample and retest. If same, consider oil change
Voltammetry/FTIR ^b (Antioxidant Trending)	D6810, D6971	More than 20 000 h: less than 25 % total RUL compared to original value. For multiple antioxidants, less than 25 % of the final remaining primary antioxidant peak	(1) Above normal degradation. Note: If Voltammetry results exceeds new oil value, check for peak shifting, new peak formation or test probe contamination Together with high acid number, indicates oil at or approaching end of service life	Investigate cause. Check turbine system for possible signs of sludge or deposit formation. Check Insolubles. Compare with other data indicating of oxidation degradation. Increase frequency of testing. (If results are erratic, consider alternate test for monitoring oxidation inhibition.) Resample and retest. If same, consider oil change



TABLE 6 Continued

Test	Method	Warning Limits ^A	Interpretation	Action Steps
Insolubles	D2273	greater than 0.1 wt %	Indicates (1) contamination of oil by equipment wear or other debris, or (2) oil or additive degradation	Investigate cause. Filter or Centrifuge oil, or both. Consider oil change. For turbines with combined turbine and hydraulic reservoirs, consider varnish prediction methods.
Foaming Test, Sequence 1 ^C	D892	exceeds following limits: tendency 450 mL and stability 10 mL	Possibly contamination or antifoam depletion. In new turbines, residual rust preventives absorbed by oil may cause problem	High tendency data should be confirmed by reservoir visual inspection. Rectify cause. Check with oil supplier regarding filtration and oil rejuvenation by bleed and feed
Air Release ^C	D3427	exceeds following limits: double the time compared to new oil	Possibly contamination or excess antifoam re-addition. In new turbines, residual rust preventives absorbed by oil may cause problem	Watch the system as required. Rectify cause. Compare with other results. Consider rejuvenating with bleed and feed
Flash Point ^C	D92	Drop 15 °C or more compared to new oil	Probably contamination	Determine cause. Check other quality parameters. Consider oil change

^A Warning limits apply at any time unless otherwise stated.

^B Consult with oil supplier regarding most appropriate methods, which may be RPVOT, Voltammetry, or FTIR or a combination thereof.

^C If contamination is suspected, additional tests such as Flash Point, Foam, Water Separability, Rust and Air Release, may be useful to determine degree and effect of contaminants present. An outside supplier or oil supplier can also assist in a more in-depth analysis.

TABLE 7 Single Shaft Combine Cycle Turbine Test Schedule, Interpretation and Recommended Action Steps

NOTE 1—Frequency (New Turbine Installation First 12 Months)—Suggested sample frequency is every 1 month to 3 months or as agreed upon with lubricant or condition monitoring provider. Normal Operation is every 4 months to 6 months or as agreed with lubricant or condition monitoring provider. The sample frequency should be used as a guide. Increased frequency (half the suggested time intervals) is recommended for a severe turbine or for oils approaching the end of their service life. Most turbines should be covered by this schedule. Sample frequency is based on continuous operation or total accumulated service time.

NOTE 2—For combined cycle systems where the gas turbine (see [Table 6](#)) and steam turbines (see [Table 5](#)) have separate lubricating circuits follow the test schedules for the individual turbine type.

Test	Method	Warning Limits ^A	Interpretation	Action Steps
Viscosity	D445, D7042	± 5 % of new oil, max Up to 20 000 h: $\Delta > (0.10 \text{ mg KOH/g}) / \text{year}$	(1) Oil is contaminated, (2) oil is severely degraded, or (3) high or low viscosity fluid added This represents abnormal deterioration. Possible causes are: (1) system conditions (temperature etc.) are severe and promote abnormal oil deterioration, (2) antioxidant depleted, (3) wrong makeup oil used, (4) contamination	Determine cause. If viscosity is low determine flash point. Change oil, if necessary. Investigate cause, increase frequency of testing—Compare with RPVOT, MPC, Voltammetry, or FTIR data, or combinations thereof. Consult with Oil Supplier for possible remedy.
Acid Number	D974 or D664	More than 20 000 h: $\Delta > (0.15 \text{ mg KOH/g}) / \text{year}$	This represents severe deterioration. The oil is at or near the end of its service life. Possible causes are: (1) system conditions (temperature etc.) are severe and promote severe oil deterioration, (2) primary antioxidant depleted, (3) or (4) above may apply	Look for signs of increased sediment on filters and centrifuge. Check RPVOT, MPC, Voltammetry, or FTIR data, or combinations thereof. If RPVOT or antioxidant level is less than 25 % of original, review status with oil supplier and consider oil change. Increase test frequency if left in system.
Appearance	Visual	hazy	Oil contains water, entrained air or solids or a combination thereof. See also Table 3 .	Investigate cause (see Table 3) and remedy, check water content or air release. Filter or centrifuge oil, or both. Check for other potential source of contamination, if needed.
Water Content	D6304	exceeds 0.02 % or 200 mg/kg	Oil contaminated. Potential water or steam leak.	Investigate and remedy cause. Remove water by centrifugation, coalescence or vacuum dehydration as appropriate. If still unsatisfactory, consider oil change or consult oil supplier.
Color	D1500	unusual or rapid darkening	This may indicate (1) contaminations, or (2) excessive degradation	Determine cause and rectify. Consider oil change
Particle Count—Cleanliness	F311 and F312 or D7647 or User defined	18/16/13 or OEM recommended limits	Source of particulates may be: (1) makeup oil, (2) dust or ash entering system, (3) wear condition in system, (4) preservatives from turbine replacement part, (5) soft contaminants due to oil degradation	Locate and eliminate source of particulates. Check oil for insolubles and wear metals. Clean system oil by filtration or centrifuging, or both.
Wear Metals	D5185	greater than 10 ppm to 20 ppm	Indicates the presence of wear conditions or contamination. See Table 4 .	Perform wear debris analysis
Additive Elements	D5185	± 25 % of the new oil	Additive depletion, wrong oil added, oil dilution, or additive precipitation/dropout	Consult with oil supplier regarding situation. Check for dilution with another oil or fluid. Check other quality parameters.
MPC—varnish test	D7843	20 dE—increased amount of varnish may need attention 30-dE—cautionary limit requiring corrective actions Up to 20 000 h: less than 50 % or greater than 25 % of original value	Source of insoluble color bodies may be soft contaminants due to oil degradation (1) Above normal degradation, (2) Higher than new oil RPVOT may result from addition of new oil or test interferences from antioxidant intermediates	Consider oil change Locate and eliminate source of contaminants. Clean system oil by adequate filtration techniques
RPVOT ^B	D2272	More than 20 000 h: less than 25 % of original value	Together with high acid number, indicates oil at or approaching end of service life	Investigate cause. Check turbine system for possible signs of sludge or deposit formation. Check insolubles. Compare with other data indicating of oxidation degradation. Increase frequency of testing. (If results are erratic, consider alternate test for monitoring oxidation inhibition.) Resample and retest. If same, consider oil change



TABLE 7 Continued

Test	Method	Warning Limits ^A	Interpretation	Action Steps
Voltammetry/FTIR ^B (Antioxidant Trending)	D6810, D6971	Up to 20 000 h: less than 50 % total RUL	(1) Above normal degradation, Note: If Voltammetry results exceeds new oil value, check for peak shifting, new peak formation or test probe contamination	Investigate cause. Check turbine system for possible signs of sludge or deposit formation. Check Insolubles. Compare with other data indicating of oxidation degradation. Increase frequency of testing. (If results are erratic, consider alternate test for monitoring oxidation inhibition.)
		More than 20 000 h: Less than 25 % total RUL compared to original value. For multiple antioxidants, less than 25 % of the final remaining primary antioxidant peak	Together with high acid number, indicates oil at or approaching end of service life	Resample and retest. If same, consider oil change
Rust Test, Procedure A	D665	Up to 20 000 h: Light fail	(1) The system is wet or dirty or both (2) The system is not maintained properly (for example, water drainage neglected, water removal equipment malfunctioning)	Investigate cause and make necessary maintenance and operating changes. Recheck Rust Test, consult with oil supplier regarding possible remedy if test result unchanged
		More than 20 000 h: Light fail greater than 0.1 wt %	Normal additive depletion in wet system Indicates (1) contamination of oil by equipment wear or other debris, or (2) oil or additive degradation	Consult oil supplier regarding rejuvenation by bleed and feed
Water Separability at 54°C ^C	D1401	greater than 3 mL stable emulsion or less than 36 mL water at 60 min, or both	Possibly pollution, contamination, degradation	Investigate cause. Filter or Centrifuge oil, or both. Consider oil change. For turbines with combined turbine and hydraulic reservoirs, consider varnish prediction methods.
Foaming Test, Sequence 1 ^C	D892	exceeds following limits: tendency 450 mL and stability 10 mL	Possibly contamination or antifoam depletion. In new turbines, residual rust preventives absorbed by oil may cause problem	Compare with other test data indicating degree of degradation. Locate and eliminate source of contaminants. Clean system by adequate filtration techniques. Consider oil change if water separability can not be restored
Air Release ^C	D3427	exceeds following limits: double the time compared to new oil	Possibly contamination or excess antifoam re-addition. In new turbines, residual rust preventives absorbed by oil may cause problem	High tendency data should be confirmed by reservoir visual inspection. Rectify cause. Check with oil supplier regarding filtration and oil rejuvenation by bleed and feed
Flash Point ^C	D92	Drop 15 °C or more compared to new oil	Probably contamination	Watch the system as required. Rectify cause. Compare with other results. Consider rejuvenating with bleed and feed
Microbial contamination ^D	D7978 or D7687	10 fold increase above established norms	Microbial growth is occurring with potential for filter plugging, system fouling, oil degradation and corrosion. Water ingress or accumulation is occurring.	Determine cause. Check other quality parameters. Consider oil change Identify source of water and make necessary maintenance or operational changes. Use filters or centrifuges, or both, to remove microbial contamination and water. In severe cases flushing or biocide treatment, or both, may be needed

^A Warning limits apply at any time unless otherwise stated.

^B Consult with oil supplier regarding most appropriate methods, which may be RPVOT, Voltammetry, or FTIR or a combination thereof.

^C If contamination is suspected, additional tests such as Flash Point, Foam, Water Separability, Rust and Air Release, may be useful to determine degree and effect of contaminants present. An outside supplier or oil supplier can also assist in a more in-depth analysis.

^D Microbes are ubiquitous in many environments and there are no universally accepted limits for microbial contamination in oils. The levels of contamination which can be tolerated will depend on the system and the type of microbial contamination. Microbes will generally be far more numerous in low point samples and samples containing water. For routine microbiological monitoring, baseline contamination levels should be established for designated sample points, which should include a system low point and a representative sample of circulating oil (before any filters or centrifuges). A ten-fold increase in microbial counts should highlight that microbial growth may be occurring. Typically, microbial counts of over 1 000 microbes/mL of oil in low point samples or over 100 microbes/mL in representative samples of circulating oil indicate contamination levels are above normal background level. Counts ten times these levels could indicate a potential for microbially related operational problems.

APPENDIX

(Nonmandatory Information)

X1. SEVERITY FACTOR CALCULATIONS

X1.1 In a previous section of this practice, mention was made of the severity of a turbine and lube oil system together with the factors that determine the severity. In a paper on turbine oil degradation⁴ the turbine severity has been defined as the “percent of fresh oil oxidation resistance lost per year due to oil reactions in the turbine oil system.” An equation was developed for turbine severity, B , as follows:

$$B = M \left(1 - \frac{X}{100} \right) / \left(1 - e^{-\frac{Mt}{100}} \right) \quad (\text{X1.1})$$

where:

B = turbine severity,

M = fresh oil makeup expressed as the percent of total charge per year,

t = years of oil use, and

X = used oil oxidation resistance in the Test Method **D2272** rotary pressure vessel test expressed as % of fresh oil.

X1.2 To be able to use this equation to obtain the severity factor for a particular system, it is apparent that both the oil makeup rate and results of the RPVOT must be known over a significant period of turbine operation. The latter requires periodic testing at 3 month to 6 month intervals for 1 year to 2 years, while the former is obtained through accurate record-keeping. In some large, multiple-unit installations having common piping and oil storage facilities, special efforts are needed to keep track of oil makeup rates for each unit.

X1.3 For greater detail on the significance of turbine oil system severity and its use in controlling oil degradation, it is recommended that the original paper be consulted.

⁴ Denherder, M. J., and Vienna, P. C., “Control of Turbine Oil Degradation During Use,” *Lubrication Engineering*, Vol 37(2), 1981, pp. 67–71.

SUMMARY OF CHANGES

Subcommittee D02.C0 has identified the location of selected changes to this standard since the last issue (D4378 – 13) that may impact the use of this standard. (Approved May 1, 2020.)

(1) Added **D4175**, **D7042**, **D7464**, **D7843**, **D7978**, **D8072**, **D8112** to Section 2.

(2) Added Section 3, Terminology.

(3) Revised subsections **6.1.3.2**, **6.1.3.2**, **6.1.5.1**, **6.1.5.2**, **9.1.2**, **9.2.1**, **9.2.2.1**, **9.2.2.2**, **9.2.3.2**, **9.2.4.2**, **9.2.6.1**, **9.2.7.1**, and **11.1**.

(4) Revised **Tables 1-7**.

(5) Added subsection **9.4**.

(6) Revised Section **7**, Sampling.

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