



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 and health practices and determine the applicability of regulatory limitations prior to use.*

2. Referenced Documents

2.1 *ASTM Standards:*²

[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](#)

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.

Current edition approved Oct. 1, 2013. Published October 2013. Originally approved in 1984. Last previous edition approved in 2012 as D4378 – 12. DOI: 10.1520/D4378-13.

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

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 Absorption
- D3427 Test Method for Air Release Properties of Petroleum Oils
- D4057 Practice for Manual Sampling of Petroleum and Petroleum Products
- 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
- D7155 Practice for Evaluating Compatibility of Mixtures of Turbine Lubricating Oils
- 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

D7720 Guide for Statistically Evaluating Measurand Alarm Limits when Using Oil Analysis to Monitor Equipment and Oil for Fitness and Contamination

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. Significance and Use

3.1 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.

4. Properties of Turbine Oils

4.1 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.

4.2 New turbine oils should exhibit good resistance to oxidation, inhibit sludge and varnish deposit formation, and provide adequate antirust, water separability, and nonfoaming 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

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

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.

5. Operational Factors Affecting Service Life

5.1 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.

5.1.1 *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.

5.1.2 *Condition of System on Start-up:*

5.1.2.1 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 hydroelectric turbine lubrication systems is provided in Guide [D6439](#) or may be sought from the equipment/lubricant supplier or other industry experts.

5.1.2.2 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.

5.1.2.3 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.

5.1.3 *Original Oil Quality:*

5.1.3.1 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.

5.1.3.2 It is advisable to obtain typical test data from the oil supplier. Upon receipt of the first oil charge, a sample of oil should be taken 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](#)).

5.1.3.3 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 insolubles. Guidance for such compatibility testing can be referenced in Practice [D7155](#) for evaluating compatibility of mixtures of turbine lubricating oils.

5.1.4 *System Operating Conditions:*

5.1.4.1 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.

5.1.4.2 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.

5.1.4.3 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.

5.1.5 *Contamination:*

5.1.5.1 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. 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](#)).

5.1.5.2 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, and insoluble particulate oil degradation products. From whatever source, contamination must be dealt with by monitoring oil condition and the use of purification devices such as filters and centrifuges on a regular basis. These can be removed by purification devices such as filters, centrifuges, coalescers, and vacuum dehydrators. Contamination of the system oil is a valid reason to change oil or flush a unit, or both, to restore system cleanliness.

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	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.

5.1.6 *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.

5.1.7 *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.

5.2 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](#).

6. Sampling

6.1 *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 location(s) to monitor the properties of the lubricant. Correct and consistent sampling techniques are vital to achieve this. The following are some suggested guidelines for proper sampling technique and sample handling techniques (see also Practice D4057). The user should have written standard operating procedures to ensure that samples are taken consistently according to good maintenance practices.

6.2 *Representative Sampling*—A sampling location that supports repeatable and representative sampling to monitor the health of the equipment and the properties of the lubricant. The

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

Schedule 2 Installation of a New Oil Charge		
Tests	Method	Recommended minimum requirements for assessment of new oil charge
Samples: After 24-h circulation in Turbine Retain approximately 4 L (1 gal)		
Viscosity	D445	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.

sample location should be upstream of filters and downstream of machine components such as bearings and gears to obtain the best data. To be representative, oil samples should be collected when the turbine is running at normal operating temperatures, loads, pressures, and speeds. This ensures insoluble material is suspended evenly throughout the system.

6.2.1 *Sampling Location*—The primary sampling port is the location where routine oil samples are taken for monitoring oil contamination, wear debris and the chemical and physical properties of the oil. Possible locations include:

6.2.1.1 *Dipping from the Tank*—Oil samples should be taken by dipping from the tank. Lubricant should be thoroughly circulated before the sample is taken.

6.2.1.2 *Oil Return Line Sampling Port* —For circulating systems, the preferred location for oil samples is on a single return line prior to entering the sump or reservoir.

6.2.2 Secondary sampling methods are to be used for measuring contamination and wear debris contributed by individual components, and can be located anywhere on the system to isolate upstream components. This is where contamination and wear debris contributed by individual components will be found:

6.2.2.1 *Sampling from a Line*—The line should contain lubricating oil which is free flowing and not deadheaded. For instance, the lines in a bearing header, an active filter, and active heat exchanger are free flowing; the lines to a gage

cabinet are deadheaded. In equipment with dual filters or heat exchangers, the inactive filters or heat exchangers do not have flowing fluid and are not suitable sampling points. When using a sampling line, it is necessary that the line has been thoroughly flushed before taking a sample. Adequate amount of flushing will depend on sampling line dimensions, length, and diameter.

NOTE 1—Test values obtained will differ depending on the sample locations. Use caution when comparing sample results from different sample points. Samples should be taken in the same manner each time to allow reliable trending of oil properties.

6.2.2.2 *Tapping from a Reservoir*—The lubricating oil must be thoroughly agitated in the reservoir and the tap line flushed before a sample can be taken.

6.2.3 An oil sample is probably not representative if: (1) the system oil is hot while the sample is cold, (2) the oil in the system is one color or clarity in a sight glass while the sample is a different color or clarity, and (3) the viscosity of the reservoir oil is different from that of the sample when both are at the same temperature.

6.2.4 It should be noted that on occasion a sample may be requested which will not be representative. At that time, sampling instructions, as specified by the requestor, must be followed. For example, a sample might be taken off the top or the bottom of a tank to check for contamination. In all cases the sample point should be marked on the sample bottle.

6.3 *Oil Sample Bottles*—Samples should be taken in a suitable sample bottle. To be suitable the bottle should be:

6.3.1 *Clean*—If in doubt about its cleanliness, use another bottle; if this is not possible, flush it out with the oil to be sampled.

6.3.2 *Resistant to the Material Being Sampled*—To verify the bottle's resistance, if time permits, allow the sample to stand in the bottle and observe its effects. Aluminum foil makes a good, resistant cap liner.

6.3.3 *Appropriate for Whatever Handling is Required*—Bottles with leaking tops and glass bottles improperly protected are not suitable for shipment. Appropriate regulations for handling and shipment of samples must be observed.

6.3.4 *Appropriate for the Analyses Required*—An extensive chemical analysis, if that is why a sample is required, cannot be done on the contents of a bottle which is too small.

NOTE 2—Some lubricant suppliers and commercial laboratories provide sample bottles which meet all these requirements. These should be used whenever possible. If frequent samples are taken, an adequate supply of containers should be available.

6.4 *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:

- 6.4.1 Customer name (if appropriate),
- 6.4.2 Site (or plant name),
- 6.4.3 Location (unit number, tank number, compartment number, and so forth),
- 6.4.4 Turbine serial number (or other ID),
- 6.4.5 Turbine service hours,
- 6.4.6 Oil service hours,
- 6.4.7 Date sample taken,
- 6.4.8 Type of oil sampled (lubricant ID),
- 6.4.9 Sampling point/port ID,
- 6.4.10 Type of purification system (filters/centrifuge, and so forth), and
- 6.4.11 Makeup (volume) since last sample was taken.

6.5 *Sampling of New Oil Deliveries:*

6.5.1 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.

6.5.2 When consignments of oil are in drums, sample them in accordance with Practice [D4057](#).

6.5.3 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.

6.5.4 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.

6.5.5 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.

6.5.6 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.

6.5.7 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.

6.6 *Preservation of Sample*—If tests are not run immediately, store the sample(s) away from strong light or excessive heat.

7. Examination of New Oil on Delivery

7.1 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.

7.2 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.

7.3 Sampling of incoming supplies should be in accordance with proper sampling procedures (see Section 6).

7.4 All samples should be immediately examined for appearance.

7.5 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.

7.6 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.

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

8. Deterioration of Turbine Oils in Service

8.1 *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:

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

8.1.2 *Thermal/Oxidative Degradation*—This can occur at hot spots in turbines. During thermal degradation at elevated temperatures, hydrocarbons are subject to thermal degradation to form unstable and insoluble compounds. These unstable compounds are easily oxidized and also tend to polymerize to form resins and sludge.

8.1.3 *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.

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

8.1.5 *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.

8.2 *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-serve 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.)

8.2.1 *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. Most commercial turbine oils are sold under ISO (International Standards Organization) viscosity classification system. Oils fall into ISO-VG-32, VG-46, VG-68, and VG-100 viscosity grades corresponding to 32, 46, 68, and 100 cSt at 40°C and to approximately 165, 240, 350, 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.

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

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	Possible Cause	Action Steps
Clear	Clear
	Foam collapsed	Air entry likely of mechanical origin or from sampling process	Investigate cause
Foam at the Surface	Stable persistent foam	High foaming tendency- Possibly contamination or antifoam depletion.	Investigate cause and conduct laboratory control test for foam
	Clear	Aeration if bubbles persist for more than 5 min.	Investigate cause
Sample contains small air bubbles at sampling then becomes clear from the bottom	Persistent entrained small air bubbles	High air entrainment- Possibly contamination, oil degradation	Investigate cause and conduct laboratory control test for air release
	Clear or slightly opaque, decanted free water	Unstable water emulsion	Determine source of water ingress
Sample cloudy and becoming clear from the top	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	Rotten eggs	Bacteria grown in an anaerobic medium	Check for presence of water. Withdraw the separated water. Test for bacteria and consult with oil supplier regarding biocide treat

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

8.2.2.1 *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. Peak locations for the additives will vary from oil to oil and the peak location 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.)

8.2.2.2 *Voltammetry*—Voltammetry is an electrochemical test technique, which can be used for measuring many antioxidant additives. The technique applies a voltage ramp through a 3 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.

8.2.3 *Oxidation Stability Reserve:*

8.2.3.1 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.

8.2.3.2 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 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](#)).

8.2.4 *Freedom from Sludge/Varnish:*

8.2.4.1 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.

8.2.4.2 Measurement of the amounts of sludge/varnish in turbine oils (for example, by porous membrane filtration) 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.

8.2.4.3 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.

8.2.5 *Particle Counting:*

8.2.5.1 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.

8.2.5.2 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.

8.2.6 *Rust Protection:*

8.2.6.1 Antirust 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 an antirust

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.

8.2.6.2 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**).

8.2.7 Water Separability:

8.2.7.1 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. 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.

8.2.7.2 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.

8.3 *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:

8.3.1 *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).

8.3.2 *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).

8.3.3 *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.

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

8.3.3.2 *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.

8.3.3.3 *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.

8.3.3.4 *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.

8.3.4 *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.

8.3.4.1 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.

8.3.4.2 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.

8.3.4.3 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. Monitoring Program

9.1 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.

9.1.1 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.

9.2 *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).

9.3 *Logging, Trending, and Interpretation of Test Data*—It is important to keep accurate records of test results and make-up. 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

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-scuff additive
Barium/ Ba		X		additives	grease
Boron/B		X	X	additive, treated coolant water	few
Cadmium/Cd	X			journal bearings	plating
Calcium/Ca		X	X	additives	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	sea water
Manganese/Mn	X			shafts, valves, blowers	few
Molybdenum/Mo	X	X		additive 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		additives, 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	galvanized steel, platings, grease

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.

9.4 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**.

9.5 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.

10. Sludge and Deposits

10.1 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, and so forth. Varnishing is usually an indication that the oil has been in service too long. 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, 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.

11. Test Schedules

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

11.1.1 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.

11.1.2 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 4–6 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.

11.1.3 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 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.

12. Keywords

12.1 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 1–3 months or as agreed upon with lubricant or condition monitoring provider. Normal operation is every 4–6 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	± 5% from original ISO VG Up to 20 000 h: 0.1–0.2 mg KOH/g increase over new oil Acid No. D974 or D664	(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 very severe, (2) antioxidant depleted, (3) wrong makeup oil used, (4) contamination (1) Oil at or approaching end of service life, (3) or (4) above may apply	Determine cause. If viscosity is low determine flash point. Change oil, if necessary. Investigate cause. Increase frequency of testing—Compare with RPVOT, Voltammetry and/or FTIR data. Consult with Oil Supplier for possible remedy. Look for signs of increased sediment on filters and centrifuge. Check RPVOT, Voltammetry and/or FTIR data. 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 10–20 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
RPVOT ^B	D2272	Up to 20 000 h: less than 50% or greater than 25% of original value 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	Up to 20 000 h: less than 50% total RUL 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
Rust Test, Procedure A	D665	Up to 20 000 h: Light fail 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) Normal additive depletion in wet system	Investigate cause and make necessary maintenance and operating changes. Recheck Rust Test, consult with oil supplier regarding possible remedy if test result unchanged Consult oil supplier regarding rejuvenation by bleed and feed

TABLE 5 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
Water Separability at 54C ^C	D1401	greater than 3 mL stable emulsion and/or less than 36 mL water at 60 min	Possibly pollution, contamination, degradation	Compare with other test data indicating degree of degradation. No action required if water content and rust procedure A is acceptable
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 15C 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 6 Gas Turbine Test Schedule, Interpretation and Recommended Action Steps

NOTE 1—*Frequency (New Turbine Installation First 12 Months)*—Suggested sample frequency is every 1–3 months or as agreed upon with lubricant or condition monitoring provider. Normal operation is every 4–6 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	± 5% from original ISO VG	(1) Oil is contaminated, (2) oil is severely degraded, or (3) high or low viscosity fluid added	Determine cause. If viscosity is low determine flash point. Change oil, if necessary.
Acid Number	D974 or D664	Up to 20 000 h: 0.1–0.2 mg KOH/g increase over new oil Acid No. 0.3–0.4 mg KOH/g increase over new oil Acid No.	This represents abnormal deterioration. Possible causes are: (1) system very severe, (2) antioxidant depleted, (3) wrong makeup oil used, (4) contamination (1) Oil at or approaching end of service life, (3) or (4) above may apply	Investigate cause, increase frequency of testing—Compare with RPVOT, Voltammetry and/or FTIR data. Consult with Oil Supplier for possible remedy. Look for signs of increased sediment on filters and centrifuge. Check RPVOT, Voltammetry and/or FTIR data. 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 10–20 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
RPVOT ^B	D2272	Up to 20 000 h: less than 50% or greater than 25% of original value 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 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	Up to 20 000 h: less than 50% total RUL less than 25% total RUL compared to original value For multiple antioxidants, less than 25% of the final remaining primary antioxidant peak greater than 0.1 wt%	(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 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
Insolubles	D2273	exceeds following limits: tendency 450 mL and stability 10 mL exceeds following limits: double the time compared to new oil	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 exceeds following limits: double the time compared to new oil	Possibly contamination or antifoam depletion. In new turbines, residual rust preventives absorbed by oil may cause problem 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 Watch the system as required. Rectify cause. Compare with other results. Consider rejuvenating with 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



TABLE 6 Continued

Test	Method	Warning Limits ^A	Interpretation	Action Steps
Flash Point ^C	D92	Drop 15C 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 1–3 months or as agreed upon with lubricant or condition monitoring provider. Normal operation is every 4–6 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	± 5% from original ISO VG Up to 20 000 h: 0.1–0.2 mg KOH/g increase over new oil Acid No. 0.3–0.4 mg KOH/g increase over new oil Acid No.	(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 very severe, (2) antioxidant depleted, (3) wrong makeup oil used, (4) contamination (1) Oil at or approaching end of service life, (3) or (4) above may apply	Determine cause. If viscosity is low determine flash point. Change oil, if necessary. Investigate cause, increase frequency of testing—Compare with RPVOT, Voltammetry and/or FTIR data. Consult with Oil Supplier for possible remedy. Look for signs of increased sediment on filters and centrifuge. Check RPVOT, Voltammetry and/or FTIR data. 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.
Acid Number	D974 or D664			
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 10–20 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
RPVOT ^B	D2272	Up to 20 000 h: less than 50% or greater than 25% of original value less than 25% of original value Up to 20 000 h: less than 50% total RUL	(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 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	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 fall Light fall	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 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
Rust Test, Procedure A	D665		(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) Normal additive depletion in wet system	Investigate cause and make necessary maintenance and operating changes. Recheck Rust Test, consult with oil supplier regarding possible remedy if test result unchanged Consult oil supplier regarding rejuvenation by bleed and feed

TABLE 7 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.
Water Separability at 54C ^C	D1401	greater than 3 mL stable emulsion and/or less than 36 mL water at 60 min	Possibly pollution, contamination, degradation	Compare with other test data indicating degree of degradation. No action required if water content and rust procedure A is acceptable
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 15C 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.

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:

$$B = M (1 - X/100)/(1 - e^{-M/100}) \quad (X1.1)$$

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 rotary bomb test must be known over a significant period of turbine operation. The latter requires periodic testing at 3 to 6-month intervals for 1 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 Den Herder, 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

Committee D02.C0 has identified the location of selected changes to this standard since the last issue (D4378 – 12) that may impact the use of this standard. (Approved Oct. 1, 2013.)

(1) Added Test Method **D7647** to Section 2, **Tables 5-7**, and **8.2.5.2**.

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