



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

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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 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. Many of the monitoring tests used for steam turbine oils are applicable to gas turbine oils.

This practice is designed to assist the user to understand how oils deteriorate and to carry out a meaningful program of sampling and testing of oils in use. Also covered are some important aspects of interpretation of results and suggested action steps so as to maximize service life.

1. Scope

1.1 This practice covers the requirements for the effective monitoring of mineral turbine oils in service in steam and gas turbines used for power generation. It includes sampling and testing schedules and recommended action steps, as well as information on how oils degrade.

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:

- D 92 Test Method for Flash and Fire Points by Cleveland Open Cup²
- D 95 Test Method for Water in Petroleum Products and Bituminous Materials by Distillation²
- D 130 Test Method for Detection of Copper Corrosion from Petroleum Products by the Copper Strip Tarnish Test²
- D 445 Test Method for Kinematic Viscosity of Transparent and Opaque Liquids (and the Calculation of Dynamic Viscosity)²
- D 664 Test Method for Acid Number of Petroleum Products

by Potentiometric Titration²

- D 665 Test Method for Rust-Preventing Characteristics of Inhibited Mineral Oil in the Presence of Water²
- D 892 Test Method for Foaming Characteristics of Lubricating Oils²
- D 943 Test Method for Oxidation Characteristics of Inhibited Mineral Oils²
- D 974 Test Method for Acid and Base Number by Color-Indicator Titration²
- D 1401 Test Method for Water Separability of Petroleum Oils and Synthetic Fluids²
- D 1500 Test Method for ASTM Color of Petroleum Products (ASTM Color Scale)²
- D 1533 Test Methods for Water in Insulating Liquids (Karl Fischer Reaction Method)³
- D 1744 Test Method for Water in Liquid Petroleum Products by Karl Fischer Reagent²
- D 2272 Test Method for Oxidation Stability of Steam Turbine Oils by Rotating Bomb²
- D 2422 Classification of Industrial Fluid Lubricants by Viscosity System²
- D 4057 Practice for Manual Sampling of Petroleum and Petroleum Products⁴
- D 4241 Practice for Design of Gas Turbine Generator Lubricating Oil Systems⁴
- D 4248 Practice for Design of Steam Turbine Generator Oil Systems⁴

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² *Annual Book of ASTM Standards*, Vol 05.01.

³ *Annual Book of ASTM Standards*, Vol 10.03.

⁴ *Annual Book of ASTM Standards*, Vol 05.02.

F 311 Practice for Processing Aerospace Liquid Samples for Particulate Contamination Analysis Using Membrane Filters⁵

F 312 Methods for Microscopical Sizing and Counting Particles from Aerospace Fluids on Membrane Filters⁵⁶

2.2 *International Organization for Standardization:*

ISO 4406 Hydraulic Fluid Power-Fluids—Method for coding level of contamination by solid particles

2.3 *Other Standard:*

National Aerospace Standard 1638⁷

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.

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.

4.2 New turbine oils should exhibit good resistance to oxidation, inhibit sludge formation, and provide adequate antirust, water separability, and nonfoaming properties. However, these properties cannot be expected to remain unchanged during the life of the oil. Some deterioration can be tolerated without prejudice to the safety or efficiency of the system. Reinhibition may improve some properties of the oil. Good monitoring procedures are necessary to determine when the properties have changed sufficiently to warrant corrective action.

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, and (6) oil makeup rate.

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. If there is an opportunity to participate in system design, it is recommended that appropriate practices be consulted (see Practice D 4241 and Practice D 4248).

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 contamination control, flushing, and purification may be sought from the equipment 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.

5.1.3 *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.

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 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 Table 1 and Table 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. These should include functional tests and checks for formation of insolubles.

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 temperatures, metals, and water are always present to some extent in these oil systems. These elements promote oil degradation.

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 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

⁵ *Annual Book of ASTM Standards*, Vol 14.02.

⁶ Available from American National Standards Institute, 11 W. 42nd St., 13th Floor, New York, NY 10036.

⁷ Available from Aerospace Industries Association of America, Inc., 1725 De Sales St., N.W., Washington, DC.

TABLE 1 Steam Turbines—Sampling and Testing Schedules [Mineral Oils]

Schedule 1 New Oil

Samples:

- (a) From transport or drums
- (b) From storage tank

Tests:

Viscosity	A
Acid No.	B
Appearance	clear and bright
Water content	no free water
Color	B
Rust test	Pass ^C
Cleanliness	D
RBOT	B

^AShould meet Classification D 2422.

^BShould be consistent with user purchase specifications, new oil reference, or manufacturer's requirement, or combination thereof.

^CShould pass D 665A for land-based turbines. Should pass D 665B for marine turbines.

^DDefinition of suitable cleanliness levels depends on turbine builder and user requirements. Filtration or centrifugation, or both, of oil into turbine and during service is strongly recommended.

 Schedule 2 Installation of a New Oil Charge^A

Sample:

After 24-h circulation. Retain approximately 4 L (1 gal).

Tests:

Viscosity	B
Acid No.	B
Appearance	clear and bright
Water content	no free water
Color	B
Cleanliness	B,C
RBOT	B,D

^AFollow recommended flushing procedures prior to installing a new oil charge whether it is an initial fill or an oil replacement.

^BShould be consistent with user purchase specifications and new oil reference.

^CDefinition of suitable cleanliness levels depends on turbine builder and user requirements. Filtration or centrifugation, or both, of oil into turbine and during service is strongly recommended.

^DImportant as a baseline to determine turbine system severity.

Schedule 3A (First 12 Months Operation—New Turbine)

Test ^A	Viscosity	Acid No.	Appearance	Water Content	Color	Rust Test	Cleanliness	RBOT
Frequency ^B	Every 1–3 months	Monthly	Daily ^C	Monthly ^C	Weekly	Every 6 months	Every 1–3 months	Every 2–3 months

Schedule 3B Normal Operation

Note 1—This schedule should be used as a guide. Increased frequency is required for a severe turbine or for oils approaching the end of their service life. Most turbines should be covered by this schedule.

Test ^A	Viscosity	Acid No.	Appearance	Water Content	Color	Rust Test	Cleanliness	RBOT
Frequency ^B	Every 3–6 months	Every 1–3 months	Daily ^C	Every 1–3 months ^C	Weekly	1 Year	Every 1–3 months	Every 6–12 months

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

^BFrequency is based on continuous operation or total accumulated service time.

^CIf product is hazy or contains water in suspension, check water content.

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.

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 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.

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.

5.2 The combination of all of the preceding operational factors for a given turbine determine 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. The more severe a turbine system, the shorter the service

TABLE 2 Gas Turbines—Sampling and Testing Schedules [Mineral Oils]

Schedule 4 New Oil

Samples:

- From transport or drums
- From storage tank

Tests:

Viscosity	A
Acid No.	B
Appearance	clear and bright
Color	B
Cleanliness	C
RBOT	B

^AShould meet Classification D 2422.

^BShould be consistent with user purchase specifications, new oil reference, or manufacturer's requirement, or combination thereof.

^CDefinition of suitable cleanliness levels depends on turbine builder and user requirements. Filtration or centrifugation, or both, of oil into turbine and during service is strongly recommended.

 Schedule 5 Installation of a New Oil Charge^A

Sample:

After 24-h (h) circulation. Retain approximately 4 L (1 gal).

Tests:

Viscosity	B
Acid No.	B
Appearance	clear and bright
Color	B
Cleanliness	BC
RBOT	BD

^AFollow recommended flushing procedures prior to installing a new oil charge whether it is an initial fill or an oil replacement.

^BShould be consistent with user purchase specifications, new oil reference, or manufacturer's requirements, or combination thereof.

^CShould agree with turbine builder and user requirements. Filtration of oil into turbine and during service is strongly recommended.

^DImportant as a baseline to determine turbine system severity.

Schedule 6A In-Service (First 6 Months Operation—New Turbine)

Test	Viscosity	Acid No.	Appearance	Color	Cleanliness	RBOT
Frequency ^A	500 h	500 h	100 h	200 h	500 h	500–1000 h

Schedule 6B In-Service Normal Operations

Note 1—This schedule should be used as a guide. Frequency should be varied depending on the turbine severity and oil condition

Test	Viscosity	Acid No.	Appearance	Color	Cleanliness	RBOT
Frequency ^A	500 h	500–1000 h	100 h	200 h	1000 h	1500–2000 h

^AFrequency is based on hours of actual 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 proper sampling techniques are followed. The following are some suggested guidelines for proper sampling technique and sampling handling techniques (see Practice D 4057).

6.2 *Representative Sampling*—To be representative, a sample must be obtained either from an agitated tank or a free-flowing line.

6.2.1 The preferred sampling method is as follows:

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.

6.2.2 The secondary sampling methods are:

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.

6.2.2.2 *Tapping from a Reservoir*—As previously described, 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 container.

6.3 *Sample Container*—Samples should be taken in a suitable container. To be suitable the container should be:

6.3.1 *Clean*—If in doubt about its cleanliness, use another container; 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 container's resistance, if time permits, allow the sample to stand in the container and observe its effects. Aluminum foil makes a good, resistant cap liner.

6.3.3 *Appropriate for Whatever Handling Is Required*—Containers with leaking tops and glass containers 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 container which is too small.

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

6.4 *Sample Markings*—A sample should be properly marked. Markings should include at least the following information:

- 6.4.1 Customer name (if appropriate),
- 6.4.2 Site,
- 6.4.3 Location,
- 6.4.4 Turbine serial number,
- 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,
- 6.4.9 Sampling point,
- 6.4.10 Type of purification system (filters/centrifuge, and so forth), and
- 6.4.11 Makeup (gallons) since last sample was taken.

6.5 *Sampling of New Oil Deliveries*:

6.5.1 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 D 4057.

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 contami-

nated 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.

8. Deterioration of Turbine Oils in Service

8.1 *How Turbine Oils Degrade*—Irrespective of initial quality, turbine oils will deteriorate in service. In the case of oils in some large steam turbines, this is a slow process so that for many years the oil may look like new. 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. Initially, hydroperoxides are formed and the process proceeds by a chain reaction.

8.1.2 *Thermal/Oxidative Degradation*—This can occur at

hot spots in turbines. At elevated temperatures, hydrocarbons are subject to thermal cracking to form unstable 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 interfering with lubrication.

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 Which Must Be Retained*—In determining the condition of the system oil for continued service, the most important properties of the used oil are: (a) viscosity, (b) oxidation stability reserve, (c) freedom from sludge, (d) freedom from abrasive contaminants, (e) anticorrosion protection, and (f) freedom from water contamination.

8.2.1 *Viscosity*—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 D 2422). 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 D 445.

8.2.2 *Oxidation Stability Reserve:*

8.2.2.1 One of the most important properties of new turbine oil is its oxidation stability. Traditionally, this has been measured by Test Method D 943 with Test Method D 2272 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 product of these processes is an insoluble sludge. Although only a minute fraction of the oil is converted in this way, sufficient sludge can form to settle in critical areas of the system and interfere with proper lubrication and cooling of bearings and moving parts.

8.2.2.2 The test method most used to determine the present state of oxidative degradation (and indirectly the oxidation stability reserve) is the acid number (Test Methods D 664 and D 974). 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 D 2272, the Rotating Bomb Oxidation Test (RBOT). This latter test is included in the recommended testing schedules (see Table 1 and Table 2).

8.2.3 *Freedom from Sludge:*

8.2.3.1 Due to the nature of the highly refined lubricant base stocks used in the manufacture of turbine oils, they are very poor solvents for sludge. 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 deposition in bearing housings, seals, gears, and pistons.

8.2.3.2 Measurement of the amounts of sludge in turbine oils (for example, by porous membrane filtration) is possible. Sludge 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 occurs.

8.2.3.3 Filtration and centrifugation assist in removing sludge 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.

8.2.4 *Freedom from Abrasive Contaminants:*

8.2.4.1 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.

8.2.4.2 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 F 311 or Methods F 312) or by particle counting, the latter normally by means of electronic particle counters. 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 -/14/11 to -/16/13 (ISO-4406) is usually considered satisfactory (the dash indicates no requirement to count the 2 micron particles).

8.2.5 *Anticorrosion Protection:*

8.2.5.1 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 D 665. 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 D 665 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 D 665 Procedure B (seawater rust test) is recommended.

8.2.5.2 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 D 130).

8.2.6 Freedom from Water Contamination:

8.2.6.1 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 D 1401) 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.

8.2.6.2 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 something has changed. A more detailed examination would be necessary to find the cause. Test Method D 1500 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 D 92 (Cleveland Open Cup).

8.3.3 *Foaming Characteristics*—Foaming characteristics are measured by Test Method D 892 which indicates both the tendency of the oil to foam and the stability of the foam after it is generated. Foaming problems have three possible origins:

8.3.3.1 *Mechanical*—Usually the most difficult to overcome if due to design feature.

8.3.3.2 *Antifoam Depletion*, (possible drop out of dispersed defoamant).

8.3.3.3 *Contamination*—In some instances this may be corrected with defoamant. Determination of the cause is necessary to effect a solution to a problem.

8.3.4 *Elemental Analysis*—Elemental analysis can be used to determine the concentration of elements associated with selected wear metals, inorganic additive, and some contaminants. System metals such as iron and copper can be accurately determined if the sample is representative and the metals are solubilized or are very finely divided. The presence of elements such as calcium could be indicative of motor oil contamination. High-silicon level would generally indicate dirt contamination.

9. Monitoring Program

9.1 A sound monitoring program is based on three factors: (1) sampling and testing of oil samples at suitable intervals, (2) logging and interpretation of test data, and (3) action steps.

9.1.1 *Sampling and Testing of Oil Samples*—Schedules should be tailored to the individual power plant depending on conditions and severity of the turbines. The schedules included in this practice are typical and should only be used as a guide. The importance of proper sampling cannot be overstressed (see Section 6). Easily run tests can be run fairly frequently at the plant. A central or base laboratory can run more complex testing with assistance from the oil supplier or outside laboratory. Examination and identification of any deposits found in the oil or removed from the system must also be taken into account. Table 1 and Table 2 contain recommended sampling and testing schedules.

9.1.2 *Logging 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 and Rotary Bomb Oxidation Test. 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 (makeup), possible intermixing of oils, and so forth. A guide to the proper interpretation of test results is part of this practice.

9.1.3 *Action Steps*—The main purpose of a monitoring program is to ensure long trouble-free operation of the turbine. 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 Table 3), usually gathered over

TABLE 3 Interpretation of Test Data and Recommended Action

Test	Warning Limit	Steam (S) or Gas (G) Turbine	Oil Life (Running Hours)	Interpretation	Action Steps
Acid No. Increase over new oil	0.1–0.2 mg KOH/g	S G	up to 20 000 h up to 3 000 h	This represents above normal deterioration. Possible causes are: (a) system very severe, (b) antioxidant depleted, (c) wrong oil used, (d) oil contaminated.	Investigate cause. Increase frequency of testing—compare with RBOT data. Consult with oil supplier for possible reinhibition.
Acid No. Increase over new oil	0.3–0.4 mg KOH/g	S, G	at any time during life of oil charge	Oil at or approaching end of service life, (c) or (d) above may apply.	Look for signs of increased sediment on filters and centrifuge. Check RBOT. If RBOT less than 25 % of original, review status with oil supplier and consider oil change. Increase test frequency if left in system.
RBOT	less than half value on original oil	S	up to 20 000 h	Above normal degradation.	Investigate cause. Increase frequency of testing.
RBOT	less than half value on original oil	G	up to 3 000 h	Above normal degradation.	Investigate cause. Increase frequency of testing.
RBOT	less than 25 % of original	S, G	at any time	Together with high acid number indicates oil at or approaching end of service life.	Resample and retest. If same, consider oil change.
Water content	exceeds 0.1 %	S	at any time	Oil contaminated. Potential water leak.	Investigate and remedy cause. Clean system by appropriate method. ^A If still unsatisfactory consider oil change or consult oil supplier.
Cleanliness	exceeds accepted limits ^B	S, G	at any time	Source of particulates may be: (a) makeup oil, (b) dust or ash entering system, (c) wear condition in system.	Locate and eliminate source of particulates. Clean system oil by filtration or centrifuging, or both.
Rust test D 665, Procedure A ^C	light fail	S	up to 20 000 h	(a) The system is wet or dirty, or both. (b) The system is not maintained properly (for example, water drainage neglected, centrifuge not operating.)	Investigate cause and make necessary maintenance and operating changes. Check rust test. Consult oil supplier regarding reinhibition if test result unchanged.
Rust test D 665, Procedure A ^C	light fail	S, G	after 20 000 h during life of oil charge	Normal additive depletion in wet system.	Consult oil supplier regarding reinhibition.
Appearance	hazy	S, G	at any time	Oil contains water or solids, or both.	Investigate cause and remedy. Filter or centrifuge oil, or both.
Color	unusual and rapid darkening	S, G	at any time	This is indicative of: (a) contamination or (b) excessive degradation.	Determine cause and rectify.
Viscosity	5 % from original oil viscosity	S, G	at any time	(a) Oil is contaminated, (b) oil is severely degraded, or (c) higher or lower viscosity oil added.	Determine cause. If viscosity is low determine flash point. Change oil, if necessary.
Flash point	drop 30°F or more compared to new oil	S, G	at any time	Probably contamination.	Determine cause. Check other quality parameters. Consider oil change.
Foam test D892	exceeds following limits	S, G	at any time	Possibly contamination or antifoam depletion. In new turbines residual rust preventives absorbed by oil may cause problem.	Rectify cause. Check with oil supplier regarding reinhibition. <i>Note</i> —Plant problems often mechanical in origin.
Sequence I	tendency—450 stability—10				

^AAppropriate methods may include centrifugation, coalescence, or vacuum dehydration.

^BDefinition of suitable cleanliness levels depends on turbine and user requirements.

^CSatisfactory for land-based turbines.

a period of time. Action should never be taken on the basis of one test result that might be incorrect either due to poor sampling or faulty testing. Resampling and retesting is necessary before proceeding. See the appropriate section of this practice for recommended action steps.

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 and Gas 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 RBOT 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 installa-

tion 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 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

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 degradation⁸ 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:

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

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 D 2722 rotary bomb 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.

⁸ Den Herder, M. J., and Vienna, P. C., “Control of Turbine Oil Degradation During Use,” *Lubrication Engineering*, Vol 37(2), 1981, pp. 67–71.

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