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"In-service Condition Monitoring of Turbine Oils"

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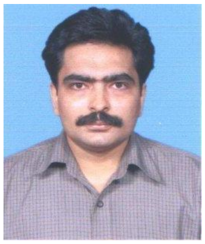

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ABSTRACT

In-service Turbine Oil analysis is an integral part of any Condition Based Maintenance Program and is a vital step in building an effective lubrication strategy. Used correctly, oil analysis on large machinery and engines not only provides valuable information about the performance of lubricating oil as well as the condition of the equipment but is also a valuable predictive and proactive tool in ensuring that equipment reliability is optimized and lubrication-related failures are minimized. However, in order to ensure continued success, it is important not only to setup the program properly, but also to review the program periodically to ensure that the program structure meets the stated reliability goals of the organization.

The practice of **turbine oil analysis** has drastically changed from its original inception in the industry. In today's computer and information age, oil analysis has evolved into a mandatory tool in a Plant's Predictive Maintenance arsenal. As a predictive maintenance tool, turbine oil analysis is used to uncover, isolate and offer solutions for abnormal lubricant and machine conditions. These abnormalities, if left unchecked, usually result in extensive, sometimes catastrophic damage causing lost production, extensive repair costs and even operator accidents. The goal of an effective turbine oil analysis program is to maximize the reliability and availability of machinery, while minimizing maintenance costs associated with oil change outs, labor, repairs and downtime. Accomplishing this goal takes time, training and patience. However, the results are dramatic and the documented savings in cost avoidance are significant. This paper presents basic oil analysis concepts for new engineers looking to improve his/her understanding of the power of turbine oil analysis.

INTRODUCTION

Optimum turbine system reliability requires a well designed lubricating system and use of a good lubricant that is free of contaminants. In addition, it requires an ongoing monitoring program to ensure that the oil quality is within specifications and that corrective action is taken to minimize contaminant generation and ingression.

Turbine oil analysis is one of the most commonly applied predictive-maintenance technologies in today's combined-cycle/cogen plant. For good reasons, the technology can provide operators with early indications of abnormal wear, corrosion or contamination occurring in such vital equipment. This is becoming even more important as turbines are built with longer and larger shafts and are operating under greater loads and at higher working temperatures with decreasing oil reservoir volumes. Oil analysis can also help operators assess the oil's chemistry and physical characteristics to determine its suitability for continued use.

WHAT IS TURBINE OIL

- A top-quality rust- and oxidation- inhibited (R&O) oil that meets the rigid requirements traditionally imposed on steam and gas turbine lubrication.
- Quality turbine oils are also distinguished by good demulsibility, a requisite of effective oil-water separation.
- Turbine oils are also widely used in other exacting applications such as for compressors, hydraulic systems, gear drives, and other equipment for which long service life and dependable lubrication are mandatory.
- Turbine oils can also be used as heat transfer fluids in open systems, where oxidation stability is of primary importance.

TURBINE OIL COMPOSITION

Modern turbine lubricants are formulated from a range of base fluids and chemical additives. The base fluid has several functions but it is primarily the lubricant which provides the fluid layer to separate moving surfaces. It also removes heat and wear particles whilst minimizing friction. Many properties of the lubricant are enhanced or created by the addition of special chemical additives to the base fluid as shown in figure 1. For example, stability to oxidation and degradation in turbine oil is improved by the addition of antioxidants whilst extreme pressure (EP) anti-wear properties needed in gear lubrication are created by the addition of special additives. The base fluid acts as the carrier for those additives and therefore must be able to maintain them in solution under all normal working conditions.

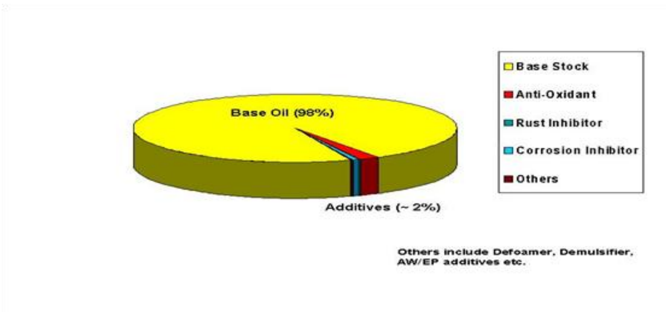


Figure 1 Typical Composition of Turbine Ois

Turbine lubricants are typically manufactured from the naturally occurring hydrocarbons present in petroleum as it is pumped from underground or extracted from geological tar sands. Figure 2 shows all the Base Oil Groups as defined by the American Petroleum Institute (API). Traditionally, base oils were solvent refined to remove impurities. This class of fluids is defined as Group I. Group II oils have become the dominant product in today's lubricant business and are referred to as "hydro-processed" oils and are superior to Group I as turbine lubricants because of their lower sulfur and aromatic content, which makes them more oxidation-resistant. Note that while these properties are highly desirable, the degradation byproducts of Group II oils are less soluble than Group I oils, thus they tend to precipitate more readily. The API defines the difference between Group II and III base oils only in terms of Viscosity Index (VI). Base oils with conventional V.I. (80-119) are Group II and base oils with an "unconventional" V.I. (120+) are Group III. Group IV Oils commonly referred to as "Synthetic Oils" are Polyalphaolefins (PAOs) based oils. Historically, PAOs based oils have had superior performance characteristics such as viscosity index (VI), pour point, volatility and oxidation stability that could not be achieved with conventional mineral oil.

Group	Typical Process	Sulphur (wt %)	Saturates (Vol. %)	Viscosity Index
I	Solvent Refining	>0.03 &/or	>90	80-119
II	All-Hydro-processing	≤0.03&	≤90	80-119
III	All-Hydro-Processing	≤0.03&	≤90	≥120
IV	Synthetic	Poly-Alpha-Olefins (PAO)		
V		Other Base Oils Not Group I, II, III or IV		

Figure 2 API Base Stock Categories

PRINCIPLES OF TURBINE OIL MONITORING

Oil analysis tests reveal information that can be broken down into three categories as stated in figure 3 & figure 4:

Lubricant Condition The assessment of the lubricant condition reveals whether the system fluid is healthy and fit for further service or needs changing. This category includes the following tests to determine the physical and chemical properties of the lubricant:

- Color, Appearance
- Viscosity @ 40°C and 100°C
- Viscosity Index (VI)
- Atomic Emission Spectroscopy (by Rotating disc electrode) to monitor for wear metals, contaminants and additives
- FTIR Spectroscopy - Fourier Transform Infra-Red Analyzer Spectrometer to monitor for Oxidation, Nitration, Sulphation, Water, Fuel Dilution. Anti-wear Additives and insolubles.
- Oxidation Stability through Rotating Pressure Vessel Oxidation Test (RPVOT) & Total Acid Number (TAN)
- Demulsibility & Foaming
- Flash point
- Air release & Specific Gravity

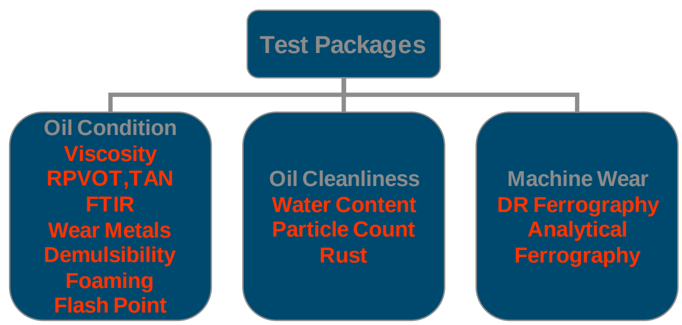


Figure 3 Three aspects of Oil Monitoring

Lubricant Cleanliness Ingressed contaminants from the surrounding environment in the form of dirt, water and process contamination are the leading cause of machine degradation and failure. Increased contamination can provide the necessary alerts to take action in order to save the oil and avoid unnecessary machine wear. The following test shall fall under this category:

- Coulometric Karl Fischer Water by ASTM D6304.
- Particle Counting as per ISO 4406/NAS 1638
- Rust per ASTM D665A

Machine Wear An unhealthy machine generates wear particles at an exponential rate. The detection and analysis of these particles assist in making critical maintenance decisions. Machine failure due to worn out components can be avoided through the utilization of healthy and clean oil. The following tests will be able to reveal pertinent information about the machine condition:

- Direct-Reading Ferrography
- Analytical Ferrography

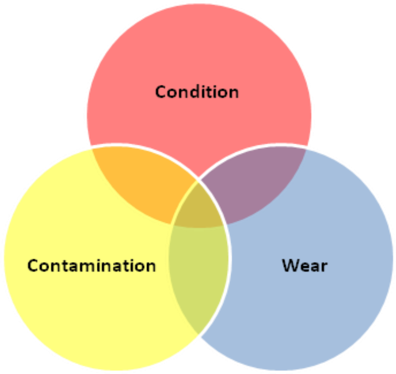


Figure 4 Information revealed from Turbine Oil Analysis Tests

PERFORMANCE CHARACTERISTICS OF TURBINE OILS

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 coupled to combine cycle 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 with regular sampling and exhaustive testing. 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 as well.

Steam Turbine Oils

The key features of steam turbine oil are superior oxidation resistance, rust/corrosion protection and good water shedding properties. Because steam turbine oils routinely carry out their function in a ‘wet’ environment, it is vital that steam turbine oil additives have very good hydraulic stability (i.e. are not degraded by the presence of water).

Steam turbines (figure 5) may be applied as main propulsion machinery for power generation and for pumping applications. Large oil changes are used and a very long service oil life is expected from Steam Turbine units. These systems generally have associated coolers, filters/coalescers and centrifugal cleaning equipment.

A well-maintained steam turbine oil with moderate makeup rates should last 20 to 30 years. When steam turbine oil fails early through oxidation, it is often due to water contamination. Water reduces oxidation stability and supports rust formation, which among other negative effects, acts as an oxidation catalyst.

Steam turbine oils operate within a ‘wet’ environment and there will invariably be some water present. For any given system, the amount of water present will stabilize at equilibrium level when the water input and output rates are the same. The water output rate will be determined by the characteristics of the oil and associated water removal systems, settling tanks, coalescers and/or centrifuges. When a system is operating normally and without additional water input via leakage, any gradual increase in water content that is evident may be due to deterioration of water shedding characteristics of the oil itself and/or reduced efficiency of the associated treatment system. Water coalescer filters may have their water removal efficiency reduced by deposition of contaminant on the active surface of the coalescer.

Varying amounts of water will constantly be introduced to the steam turbine lubrication systems through gland seal leakage. Because the turbine shaft passes through the turbine casing, low-pressure steam seals are needed to minimize steam leakage or air ingress leakage to the vacuum condenser. Water or condensed steam is generally channeled away from the lubrication system but inevitably, some water will penetrate the casing and enter the lube oil system. Gland seal condition, gland sealing steam pressure and the condition of the gland seal exhauster will impact the amount of water introduced to the lubrication system. Typically, vapor extraction systems and high-velocity downward flowing oil create a vacuum which can draw steam past shaft seals into the bearing and oil system. Water can also be introduced through lube oil cooler failures, improper powerhouse cleaning practices, water contamination of makeup oil and condensed ambient moisture.

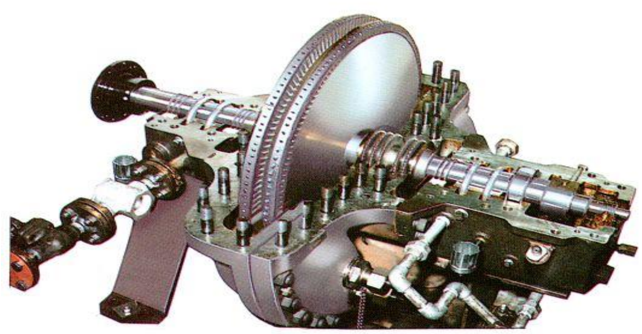


Figure 5 Typical Steam Turbine unit

In many cases, the impact of poor oil-water separation can be offset with the right combination and quality of additives including antioxidants, rust inhibitors and demulsibility improvers.

Excess water may also be removed on a continuous basis through the use of water traps, centrifuges, coalescers, tank headspace dehydrators and/or vacuum dehydrators. If turbine oil demulsibility has failed, exposure to water-related lube oil oxidation is then tied to the performance of water separation systems.

Heat will also cause reduced turbine oil life through increased oxidation. In utility steam turbine applications, it is common to experience bearing temperatures of 49ºC to 71ºC and lube oil sump temperatures of 49ºC. The impact of heat is generally understood to double the oxidation rate for every 10 degrees above 60ºC.

A conventional mineral oil will start to rapidly oxidize at

temperatures above 82ºC. Most tin-babbited journal bearings will begin to fail at 121ºC, which is well above the temperature limit of conventional turbine oils. High-quality antioxidants can delay thermal oxidation but excess heat and water must be minimized to gain long turbine oil life.
ISO VG 32 & 46 grades are usually used for equipment without gearing, while an ISO VG 68 grade will normally be used for geared equipment or where higher temperatures are found. Such oils will usually be identified by an EP suffix.

Industrial Gas Turbine Oils

In general, industrial gas turbine system lubrication requirements are satisfied by steam turbine oil technology. Viscosity grade selection is largely determined by any associated transmission gearing as for steam turbines. The major difference between the way in which the oil is required to work between a steam and gas turbine is that a gas turbine lubricant will be operating in a 'dry' environment unless water is entering the system via a leakage.
For most large gas turbine frame units, high operating temperature is the leading cause of premature turbine oil failure. The drive for higher turbine efficiencies and firing temperatures in gas turbines has been the main incentive for the trend toward more thermally robust turbine oils. Today's large frame units operate with bearing temperatures in the range of 71ºC to 121ºC. Next-generation frame units are reported to operate at even higher temperatures. Gas turbine Original Equipment Manufacturers (OEMs) have increased their suggested limits on RPVOT - ASTM D2272 (Rotation Pressure Vessel Oxidation Test) and TOST - ASTM D943 (Turbine Oil Oxidation Stability) performance to meet these higher operating temperatures.
As new-generation gas turbines are introduced into the utility market, changes in operating cycles are also introducing new lubrication hurdles. Lubrication issues specific to gas turbines that operate in cyclic service started to appear in the mid-1990s. Higher bearing temperatures and cyclic operation lead to the fouling of system hydraulics that delayed equipment start-up. Properly formulated hydrocracked turbine oils were developed to remedy this problem and to extend gas turbine oil drain intervals.

Aero-derivative Gas Turbine Oils

Aero-derivative gas turbines (figure 6) present unique turbine oil challenges that call for oils with much higher oxidation stability. Of primary concern is the fact that the lube oil in aero-derivative turbines is in direct contact with metal surfaces ranging from 204ºC to 316ºC. Sump lube oil temperatures can range from 71ºC to 121ºC. These compact gas turbines utilize the oil to lubricate and transfer heat back to the lube oil sump. In addition, their cyclical operation imparts significant thermal and oxidative stress on the lubricating oil. These most challenging conditions dictate the use of high purity synthetic lubricating oils. Average lube oil makeup rates of 0.6 liters per hour will help rejuvenate the turbo oil under these difficult conditions.
Current technology turbine oils for land-based power generation turbines are described as 5 cSt turbo oils. Aero-derivative turbines operate with much smaller lube oil sumps, typically 1000 liters or less. The turbine rotor is run at higher speeds, 8,000 to 20,000 rpm, and is supported by rolling element bearings.
Synthetic turbo oils are formulated to meet the demands of military aircraft gas turbo engines identified in Military Specification (MIL) format. These MIL specifications are written to ensure that similar quality and fully compatible oils are available throughout the world and as referenced in OEM lubrication specifications.

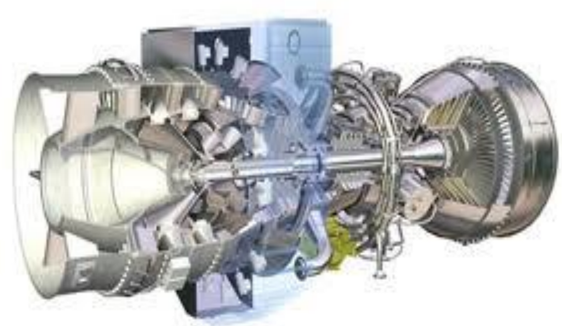


Figure 6 Typical Aero derivative Gas Turbine unit

Type II turbo oils were commercialized in the early 1960s to meet demands from the U.S. Navy for improved performance, which created MIL - L (PRF) - 23699. The majority of aero-derivatives in power generation today deploy these Type II, MIL - L (PRF) - 23699, polyol ester base stock, synthetic turbo oils. These Type II oils offer significant performance advantages over the earlier Type I diester-based synthetic turbo oils.
Enhanced Type II turbo oils were commercialized in the early 1980s to meet the demands from the U.S. Navy for better high-temperature stability. This led to the creation of the new specification MIL - L (PRF) - 23699 HTS in November 1994.

STANDARD PRACTICE FOR IN-SERVICE MONITORING OF MINERAL TURBINE OILS (ASTM D4378) FOR STEAM AND GAS TURBINES

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.
ASTM D4378-08 standard practice (figure 7) 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 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 use. This practice is performed in order to collect data and to monitor trends which suggest any signs of lubricant deteriorating. This can be used as a guide for the direction of system maintenance to ensure a safe, reliable and cost-effective

operation of the monitored plant equipment. Also covered are some important aspects of interpretation of results and suggested action steps so as to maximize service life.

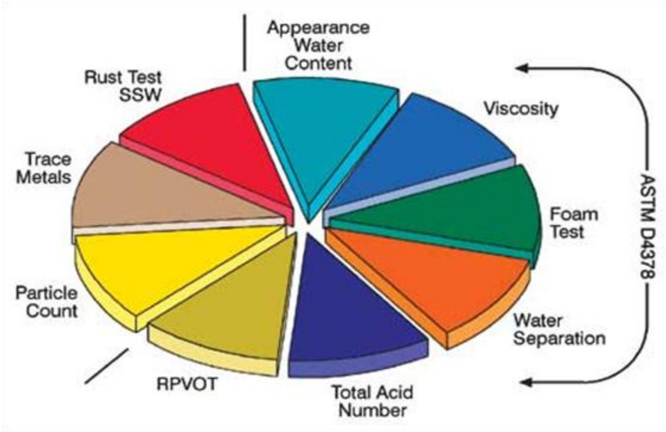


Figure 7 ASTM D4378-Standard Practice for in-service monitoring of Turbine oils

TURBINE LUBE OIL ANALYSIS TEST PACKAGES

All Turbine Oils need to measure for Viscosity @ 40^{o}C and 100^{o}C - Kinematic (ASTM D445)

This method measures an oil's resistance to flow at a specific temperature (40°C or 100°C). This test is indicative of a lubricant classification by grade, oxidation and contamination. Viscosity is one of the most important properties of a lubricant as it determines both the film thickness of the oil and how readily the lubricant will flow into the narrow area separating the moving metal parts. The oil film thickness under hydrodynamic lubrication condition is critically dependent on the oil's viscosity characteristics. In addition and most important, both journal and thrust bearings associated with steam and gas turbines are governed by tight clearances which can be directly affected by oil viscosity. Changes in oil viscosity may be indicative of changes in oil chemistry due to contamination, high shear rates and/or excessive temperature. An increase in oil viscosity could result in sluggish oil flow and excessive work being performed to generate the necessary oil film. On the other hand, a decrease in oil viscosity can result from contamination with fuel or with lighter hydrocarbon and would not allow the required oil film thickness to be sustained. Changes in oil viscosity can result in unwanted turbine rotor positioning, both axially and radially. Axial movements will directly impact turbine blade efficiency and can lead to blade damage whereas radial movements caused by changes in oil viscosity can result in "oil whip". Most commercial turbine oils are sold under the International Standards Organization (ISO) 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 (Classification D 2422). Unless the oil has been contaminated or severely oxidized, viscosity should remain consistent over years of service. ASTM D4378-08 proposes a five percent change from the initial viscosity as a warning limit. Testing for viscosity should be conducted on a quarterly basis, at the very least.

Viscosity Index - Kinematic (ASTM D2270)

This index is used as a measure of the variation in kinematic viscosity due to changes in the temperature of an oil lubricant between 40°C and 100°C. A higher viscosity index (VI) indicates a smaller decrease in kinematic viscosity with increasing temperature of the oil lubricant while low VI values represent a greater viscosity decrease at elevated temperatures. Changes in the viscosity index may indicate a degradation of oil, contamination or the use of the wrong oil. Used turbine oils rarely show significant viscosity changes due to degradation. Occasionally, viscosity increases are due to an emulsion with water contamination. A turbine oil VI of at least 90 is normally specified by most gas and steam turbine OEMs. The viscosity index for turbine oils do not vary much in-service and, hence may not be tested for condition assessments.

Total Acid Number (TAN) - a measure of acidity (ASTM D644)

This method determines the amount of acidity in a lubricant. New and used oils may contain acidic compounds which are present as additives or as degradation products. As the oil is exposed to high temperatures during operation, thermal degradation or oxidation occurs, thus increasing the concentration of acidic constituents (figure 8). Organic acids formed by oxidation can corrode bearing surfaces and should be addressed in a timely manner. The acid number is used to track the oxidative degradation of oil in service. Oil changes are indicated when the acid number reaches a predetermined level for a given lubricant and application. An increase in TAN is indicative of oil oxidation (or loss of antioxidant) or hydrolysis and represents irreversible oil deterioration. A sudden increase in the acid number may be indicative of abnormal operating conditions. ASTM-4378-08 offers guidelines of 0.3 to 0.4 mg KOH/g increase over the new oil value as an upper warning level. Testing for TAN should be conducted at least on a quarterly basis. If the TAN test shows a significant increase in acidity since the last test, it may also be desirable to perform a Rotary Pressure Vessel Oxidation Test (RPVOT) which measures the oxidation stability of the oil and indicates if the antioxidant additives in the oil have been depleted, requiring replacement of the oil in the near future.

Figure 8 Severe oil oxidation resulting in plugged filters

Measure of Oxidation Stability by RPVOT (ASTM D2272)
This test method utilizes an oxygen-pressured vessel to evaluate the oxidation stability of new and in-service turbine oils in the presence of water and a copper catalyst at 150°C (figure 9). It is used for specification of new oil and should be used as a monitoring tool to assess the remaining oxidation test life of in-service oils to provide advance warning as the anti-oxidant is gradually consumed. Oxidation stability of turbine oils will gradually decrease in service mainly due to catalytic effects of iron and copper metals in the system as well as by the depletion of the anti-oxidant. As the oxidation stability reserve decreases, acidic compounds are produced which in turn undergo a further reaction to form insoluble compounds such as sludge and deposit. These oxidation products will then promote corrosion, attack seals and can interfere with proper lubrication by settling in critical areas of the system such as governor parts, bearing surfaces and lube oil coolers. A severely oxidized turbine oil will rapidly consume the antioxidant package and can form varnishes on hot bearing surfaces that retard heat transfer and can overheat heat journal bearings (figure 10). In addition, severely oxidized oils can also foul turbine control elements and heat exchangers. ASTM D4378-08 identifies an RPVOT value decline to 25 percent of the initial new oil RPVOT value with an increase in Total Acid Number (TAN) as a warning limit. Many turbine OEMs do specify that when the RPVOT value decreases to 25 percent of the new oil value, the oil is deemed non-acceptable for continued use and should be replaced. RPVOT testing for oxidation stability should normally be conducted on an annual basis or just before the scheduled outages. An increased frequency is recommended as the turbine oil approaches 50 percent of its initial RPVOT value.

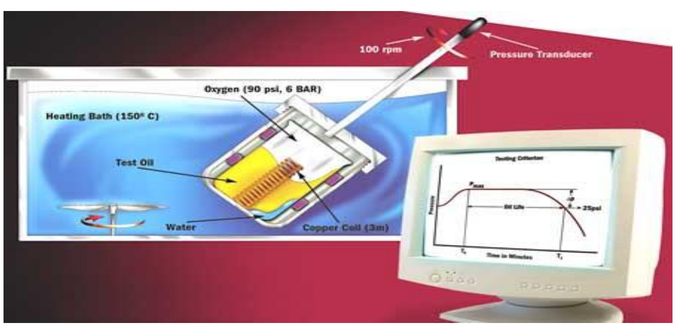


Figure 9 Measure of Oxidation Stability by RPVOT

Figure 10 Varnish formations on a gas turbine bearing and load gears

Spectrometric - Metal Analysis – Dissolved Metals ICP-AES (ASTM D5185)
This technique is used to analyze metals in oil resulting from wear, contamination and additives. Only the dissolved and very small particulate forms of the metals in the oil are detected and analyzed. The concentrations of wear metals can be indicative of abnormal wear (figure 11) while the concentrations of additive metals may indicate depletion of the additives or the use of incorrect oil. Contamination metals from coolants or the environment will also be detected. It is always advisable to establish base line values of the wear metals in a new oil sample to be compared with subsequent used oil sample test results. An increase of 4 ppm or more, of any wear metal, between samples, or levels exceeding 10 ppm is considered abnormal. Testing and trending for wear metals should be done on a quarterly basis. Figure 12 gives an outline of wear metals and their potential sources.

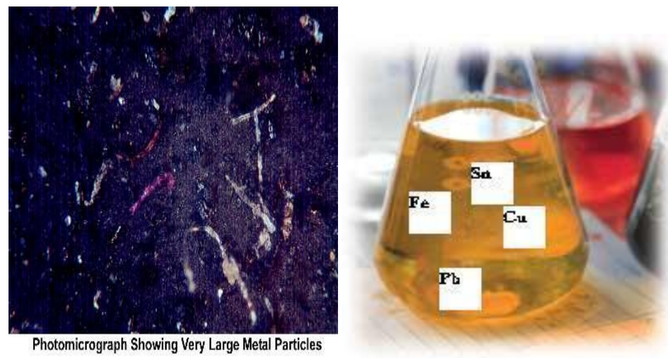


Figure 11 Photomicrograph showing large particulates wear metals

Wear Metal	Potential Sources
Iron	Accessory drive gearbox gears and bearings Generator set reduction gearboxes Compressor set speed increaser and decreaser gearboxes
Copper	Engine bearings and seals, thrust bearings, bearing cages, accessory drive gearbox bearings, boost compressor bearings and seals, babbitt material, reduction gearbox bearings and accessories pumps etc.
Lead	Engine bearings and seals, thrust bearings, boost compressor bearings and reduction gearbox bearings, speed increaser and decreaser gearboxes
Tin	Engine bearings and seals, accessory drive gearbox bearing cages, boost compressor bearings, babbitt material and reduction gearbox bearings
Silver	Engine bearing overlays and seal overlays
Antimony	Reduction gearbox bearings, radial bearing babbitt material
Aluminum	Present in labyrinth seals of high temperature compressors and in buffer gas seals.

Figure 12 Wear metals and their potential sources

Water is undesirable but an inevitable contaminant – Karl Fischer (ASTM D6304 Procedure C)
This is a method that extracts water from an oil sample and determines the amount of water using a Karl Fischer (KF) titration (figure 13). Water is an undesirable, but inevitable contaminant that promotes metal corrosion. Excessive water in the oil destroys the lubricant's ability to separate moving parts, allowing severe wear to occur. In addition, water affects corrosion rates, oil degradation resulting in loss of lubrication and premature plugging of filters, minimizing the effect of additives and supporting the growth of bacteria. Testing for water especially for steam turbines is very important to minimize the risk of the possible undetected turbine oil

oxidation and rust formation. Excessive water will also alter (increase or decrease) oil's viscosity depending on conditions.

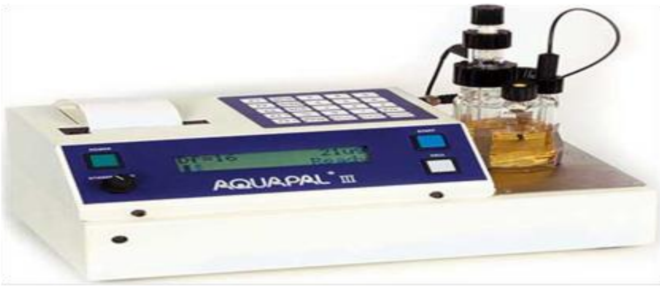


Figure 13 Measure of water content using Karl Fischer Titration method

When excessive water is present in bulk, the tendency to separate from the oil phase will allow it to collect at the bottom of oil tanks or in a stagnated area in pipelines. Water in turbine oil in warm storage tanks can also promote the spread of microbial growth that will foul system filters and small-diameter gauge and transducer line extensions. In addition, finely divided water particles can remain in permanent dispersion in the oil and can disrupt the hydrodynamic and corrosion properties of the oil depending upon its emulsion characteristics thereby affecting turbine bearing life (figure 14). ASTM D4378-08 identifies 1000 ppm or 0.1 percent of water as a warning level, while some gas and steam turbine OEMs have identified 2000 ppm of water in the oil layer as the criterion to be used for oil change out or oil reconditioning to remove both standing water and water dispersed in the oil by centrifuging or other methods. Testing for water should be conducted on a quarterly basis at a minimum and a target value of less than 200 ppm is normally recommended for in-service oils.

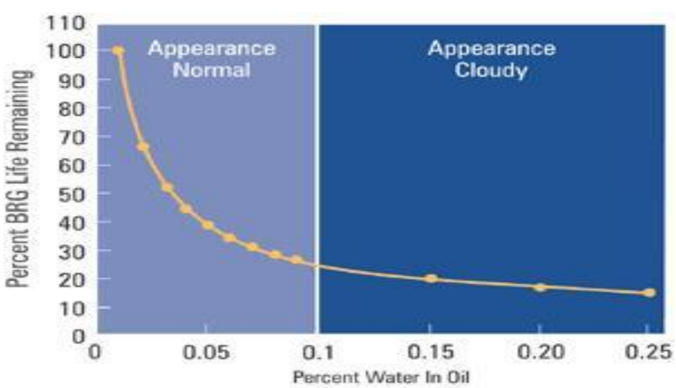


Figure 14 Percent water content in oil affecting bearing life

ISO Cleanliness Requirement (IS0 4406, NAS 1638)

This is a method used to count and classify particles in an oil or fuel according to size ranges as specified by ISO. Based on the particles per size range, a cleanliness code is assigned to the fluid which can be compared to equipment specifications. It can determine the efficiency of filters as well as identify when abnormalities are occurring. The three-range number ISO cleanliness code correlates to concentrations of particles larger than 4, 6, and 14 microns counted per ml of oil sample. Each code number correlates to a particle concentration range and can be found in a range number table in ISO 4406:1999. Excessive bearing wear can occur if tight cleanliness standards are not maintained (figure 15). Knowledge of the machine clearances and particle sizes that are indicative of wear can yield a particle size to focus on and provide information about the particle sizes that are present in greatest quantities. In rolling element bearings generally associated with aero-derivative turbines, the particle size of interest might be three microns and above; in a journal bearing, the particle size of interest might be six microns and above. Such tight clearances dictate the need for clean oil. Tables given in figure 16 and figure 17 respectively give the machine/component target ISO and AS4059 (Previously NAS 1638) cleanliness codes. Turbine OEMs offer specific guidelines on recommended cleanliness levels. An OEM normally specifies an average turbine oil cleanliness level target of ISO 16/14/12 or an NAS 1638 cleanliness level of 6. Testing for ISO cleanliness should be conducted on a quarterly basis at the very least.

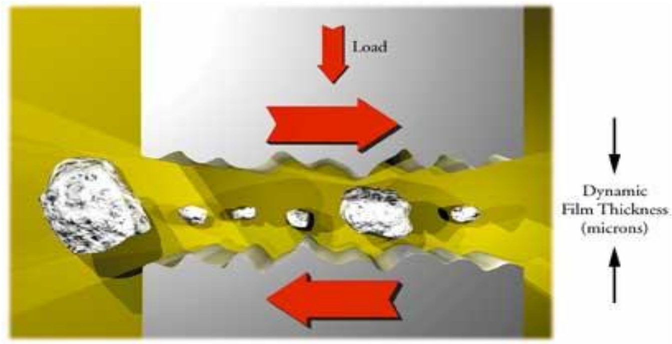
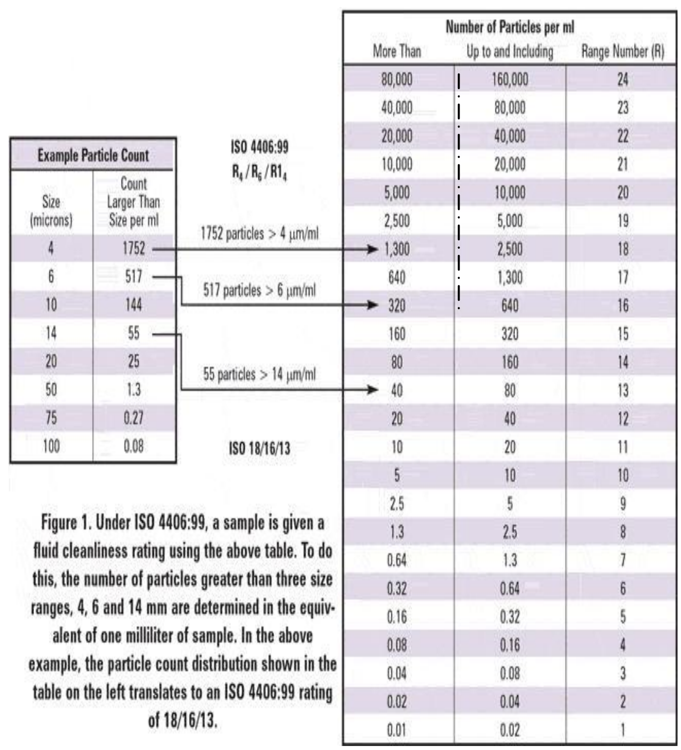


Figure 15 Dynamic film thickness affected by excessive particulate in oil



Example Particle Count	
Size (microns)	Count Larger Than Size per ml
4	1752
6	517
10	144
14	55
20	25
50	1.3
75	0.27
100	0.08

ISO 4406:99
$R_4 / R_6 / R1_4$
1752 particles > 4 μm/ml
517 particles > 6 μm/ml
55 particles > 14 μm/ml
ISO 18/16/13

Number of Particles per ml		
More Than	Up to and Including	Range Number (R)
80,000	160,000	24
40,000	80,000	23
20,000	40,000	22
10,000	20,000	21
5,000	10,000	20
2,500	5,000	19
1,300	2,500	18
640	1,300	17
320	640	16
160	320	15
80	160	14
40	80	13
20	40	12
10	20	11
5	10	10
2.5	5	9
1.3	2.5	8
0.64	1.3	7
0.32	0.64	6
0.16	0.32	5
0.08	0.16	4
0.04	0.08	3
0.02	0.04	2
0.01	0.02	1

Figure 1. Under ISO 4406:99, a sample is given a fluid cleanliness rating using the above table. To do this, the number of particles greater than three size ranges, 4, 6 and 14 mm are determined in the equivalent of one milliliter of sample. In the above example, the particle count distribution shown in the table on the left translates to an ISO 4406:99 rating of 18/16/13.

Figure 16 Target ISO cleanliness codes

Size	Maximum Contamination Limits (Particles/100mL)				
ISO 4402 or Optical Microscope*	>1 µm	>5 µm	>15 µm	>25 µm	>50 µm
ISO 11171 or Electron Microscope**	>4 µm(c)	>6 µm(c)	>14 µm(c)	>21 µm(c)	>38 µm(c)
Size Code	A	B	C	D	E
Class 000	195	76	14	3	1
Class 00	390	152	27	5	1
Class 0	780	304	54	10	2
Class 1	1,560	609	109	20	4
Class 2	3,120	1,220	217	39	7
Class 3	6,520	2,430	432	76	13
Class 4	12,500	4,860	864	152	26
Class 5	25,000	9,730	1,730	306	53
Class 6	50,000	19,500	3,460	612	106
Class 7	100,000	38,900	6,920	1,220	212
Class 8	200,000	77,900	13,900	2,450	424
Class 9	400,000	156,000	27,700	4,900	848
Class 10	800,000	311,000	55,400	9,800	1,700
Class 11	1,600,000	623,000	111,000	19,600	3,390
Class 12	3,200,000	1,250,000	222,000	39,200	6,780

* Particle size based upon longest dimension.
** Particle size based upon projected area equivalent diameter.

Figure 17 Target AS4059 (Previously NAS 1638) cleanliness codes

Anti-Rust Protection-Critical for Turbines (ASTM D665 A)

The relative ability of an oil to prevent rusting is critical in turbine and other systems which may contaminate with water. Rust particles act as oxidation catalysts and can cause abrasive wear in journal bearings. Antirust protection provided by the lubricant is of significant importance for turbine systems. New turbine oils usually contain an antirust inhibitor but while in service this additive can become depleted by removal with water or by a chemical reaction with contaminants (figure 18 & 19). In-service oil testing should be conducted with distilled water as identified in D665A for land based turbines and with synthetic sea water as per test method D665B for turbines in marine environments. ASTM D4378-08 considers a "light fail" as a warning limit. Testing for rust should be conducted on an annual basis if the lube oil system is wet or dirty and exposed to water.

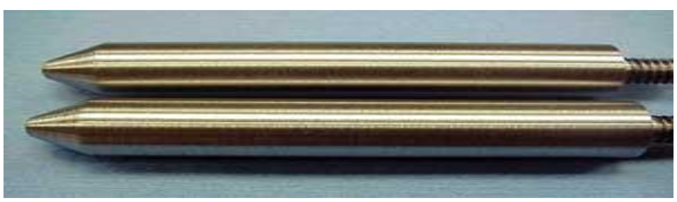


Figure 18 Lubricant with sufficient rust inhibitors

Figure 19 Lubricant without sufficient rust inhibitors

Foaming Characteristics (ASTM D892)

This technique determines the foaming characteristics of lubricating oil by determining both foam creation i.e. foaming tendency as well as foam collapsing i.e. foaming stability characteristics at different temperatures. Foam tendency is the foam volume measured in a graduated cylinder after five minutes of blowing air at a constant rate through the lube oil sample. Stability represents the volume amount after 10 minutes of settling time. A foam stability of less than 5 ml is a good indication that foam bubbles are breaking and the turbine should not experience foam operational problems. Mixing of air and oil is inevitable in a circulating turbine lube oil system because of air discharge across air/oil seals, agitation and the essentially open environment of the lube oil tank. Oils exhibit different foaming characteristics as a result of the base stock and, more importantly, the anti-foaming additive that is used (figure 20). The foaming tendencies of oil can be a serious problem in systems such as high speed gearing, high volume pumping and splash lubrication as excessive foaming can cause cavitation, inadequate lubrication and overflow loss of lubricant which could lead to mechanical failure. Field experience has indicated that foaming levels increase significantly soon after the oil is placed in service. If the foam level in the turbine sump is 150 mm or less and does not overflow the sump or cause level monitoring errors, the turbine oil foam should not be a concern. ASTM D4378-08 specifies warning limits of tendency 450 ml with a stability of 10 ml under Sequence I. When addressing foam problems, cleanliness, contamination or mechanical causes should be investigated before considering addition of a defoamant. However excessive use of antifoamants can have a negative effect on air release properties. Testing for foam should be conducted only when foaming presents an operational problem and for product compatibility testing.

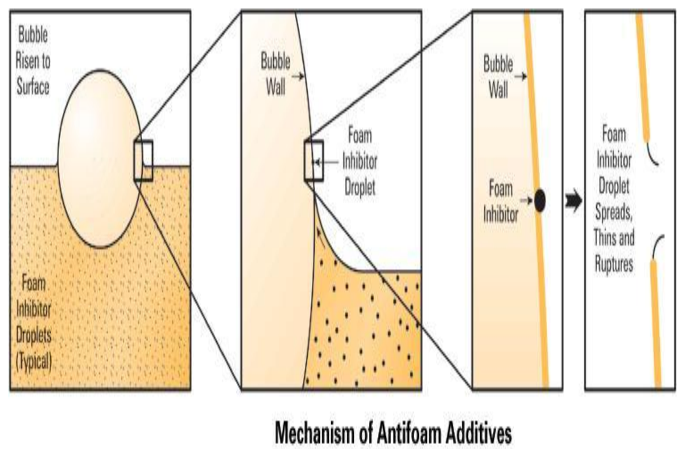


Figure 20 Mechanism of Antifoam additives

Water Separability/Demulsibility (ASTM D1401)

This test method determines the water separation characteristics of oils subjected to water contamination and turbulence. It is used for specification of new oil and for monitoring oil that is in service. Water separation characteristics are important to lube oil systems that have had direct contact with water. Mixture of oil and water, known as emulsion, can be quite stable if well agitated. In contrast to other applications, such as metal working where stability of emulsions is desirable, oil-in-water emulsions are to be avoided in turbine oils because of the corrosive effect of water and the inadequacy of water as a lubricant (figure 21). Demulsibility can be compromised by excessive water contamination or the presence of polar contaminations and impurities. Oil with good demulsibility characteristics can provide a clean break between water and oil in the system sump, where water can then be drained from the system. Turbine oil concentrations as low as 300 ppm or 0.03 percent has been proven to degrade demulsibility. ASTM D 4378-08 does not provide any specific warning limits for demulsibility. Some turbine OEMs require complete separation or emulsion reduction to 3 ml or less after 30 minutes as acceptance criteria for new oils. In-service oil warning limits of 15 ml or greater of emulsion after 30 minutes should serve as a fair warning limit. The impact of demulsibility depends on the system residence time and anticipated levels of water contamination. Small sumps with lower residence times will require better demulsibility performance than larger sumps. Testing for demulsibility should be conducted on an annual basis if the lube oil system is exposed to water.

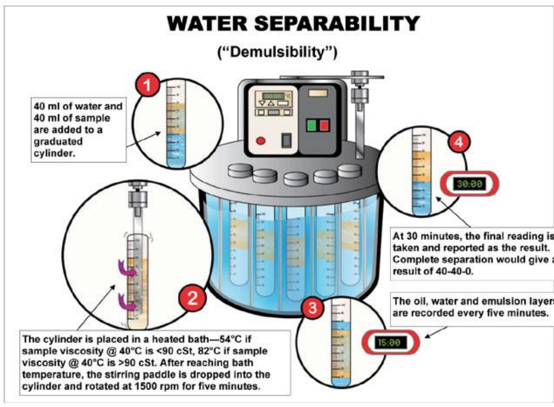


Figure 21 Water Separability- an important consideration for Turbine oils

Air Release (ASTM D3427)

The ability to allow air bubbles to separate from the oil is a critical property that can deteriorate with service or with excessive silicon containing additives. Air entrainment (aeration) consists of small bubbles trapped beneath the surface of the oil. When a sufficient quantity of air is entrained in the oil due to either stabilization of air bubbles at high pressure or dissolution of air in oil, the oil becomes compressible because of the compressibility of air (figure 22). This gives rise to erratic motion and will reduce the film strength of the oil leading to potential problems with physical contact between shafts and bearings, and the meshing of gear teeth. Entrained air can also result in destructive behaviour on the discharge side of lube oil pumps. Problems such as violent vibration of lube oil hoses leading to eventual failure of such hoses, and pump cavitation leading to premature pump failure can be attributed to air entrainment in some cases. In turbines with small reservoirs and short residence time, entrained air mixtures could be sent to bearings and critical hydraulic control elements. The use of a defoamant may increase the time air is trapped in the oil. Anti-foam agents decrease foam but can aggravate air entrainment.

Some steam and gas turbine OEMs specify air release limits in their initial oil specifications as well as that required for in-service turbine oils. These limits can range from four minutes (for new oils) to as high as ten minutes (for used or in-service oils). Air release for turbine oils normally do not vary much with in-service time and, therefore, may not need to be tested for condition assessments.

Figure 22 Air Release testing for Turbine oils

FTIR Spectroscopy - Fourier Transform Infrared Analysis

FTIR analysis provides information on the state of the oil and the machinery from which it comes. Indicators of chemical degradation include oxidation, nitration, sulfation, ester breakdown and antiwear additive depletion. Indicators of contamination include soot, water and glycol and fuel dilution. This technique is an excellent trending tool. The Fourier-Transform Infra-red Oil Analyzer Spectrometer test results shall be quantified in abs/cm (absorbance/cm) based on the areas displaced by the spectra peaks at the wave number corresponding to base stock degradation, additives depletion and fluid contamination (figure 23). Fourier Transform Infrared Spectroscopy is a technique which involves absorption of infrared energy by different molecules at different frequencies. As oil oxidizes, FTIR will start to detect oxidation build-up. FTIR has certain limitations for use on synthetics lubricants.

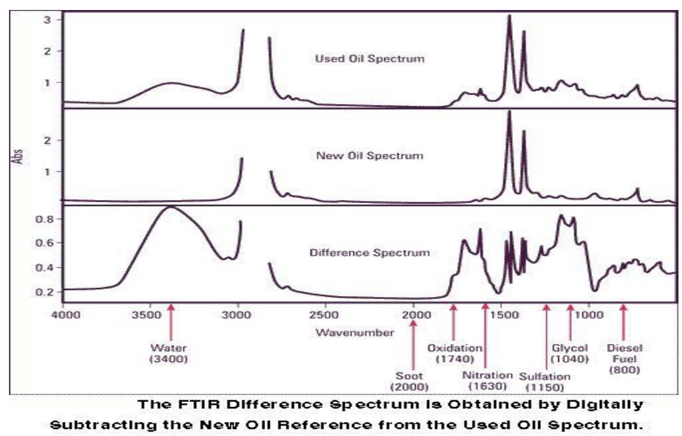


Figure 23 FTIR Spectroscopy- an excellent trending tool

Flash Point – A must for safety- Cleveland Open Cup (ASTM D92)

This test determines the temperature at which the oil will form a flammable mixture with air (figure 24). The flash point can be compared with standard specifications to determine if the oil meets the specification. It is often used as an indicator of fuel dilution or to confirm product integrity from contamination. This flammability characteristic is critical from the standpoint of safety, particularly in unattended field sites and is generally a function of the base stock oil. For in-service oil evaluation, the flash point temperature provides information with regards to presence or loss of volatile components. ASTM D4378-08 identifies a drop of 30°F (17°C) or more from the original oil value as a warning limit. Normal degradation of turbine oils has little effect on the flash point. Flash point testing should be conducted only if product contamination from a different oil or fuel dilution is suspected.

Figure 24 Testing for Flash Point

DESIGNING A WORLD CLASS TURBINE OIL ANALYSIS PROGRAM (Figure 25)

Step 1: Program Design

The overall structure and foundation of an oil analysis program should be based on sound reliability engineering goals. These goals should guide the end user through the process of designing and implementing the program. For example, if the plant has experienced a history of turbine bearing failures believed to be related to fluid contamination, every aspect of the oil analysis program, from sample valve location to selecting test slates and assigning targets and limits should be governed by the stated reliability objective - in this case, extending the mean time between failure (MTBF) of the turbine bearings.

A program designed around this type of sound footing, requires the development of an overall oil analysis strategy in conjunction with a failure mode and effects analysis (FMEA). This is often performed as part of a more comprehensive reliability-centered maintenance (RCM) program. The FMEA process looks at each critical asset, and based on component type, application and historical failures, allows test slates, sampling frequencies and targets and limits to be selected. These items will address the most likely or prevalent root cause of the failure.

While the lab's experience in developing effective oil analysis programs can be used to support the design process, it is ultimately the end user's responsibility to ensure the program meets the company's goals and reliability objectives. In particular, attention should be paid to the types of test procedures used by the lab under different circumstances. In poorly designed programs, where lab and test selection is often driven by the per-sample cost, the lowest bidder typically becomes the lab of choice. However, for the sake of perhaps 50 cents to one dollar per sample, the test slate selection may include tests that provide little to no value.

Step 2: Sampling strategy

Of all the factors involved in developing an effective program, a sampling strategy has perhaps the single largest impact on success or failure. With oil analysis, the adage "garbage in, garbage out" definitely applies. While most oil analysis labs can provide advice on where and how to sample different components, the ultimate responsibility for sampling strategy must rest on the end user's shoulders.

Of course, any sample strategy involves more than just sampling location. Sampling method and procedure, bottle cleanliness and hardware all factor into the sampling equation.

Perhaps second only to location in importance, is the provision of collateral information when the sample is submitted to the lab. For industrial equipment, as few as one sample out of 10 is submitted to the lab with appropriate information about oil type, hours on the oil, filter changes or the addition of make-up oil. Without suitable information, oil condition parameters such as viscosity or acid number cannot be compared to the new oil and trend analysis cannot be performed effectively.

Without exception, it is the responsibility of the end user to ensure that any and all pertinent information that can be used by the lab in the analysis and interpretation of the data be sent to the lab with each and every sample. Failure to do so simply means that the lab is guessing at whether or not any of the data is significant and should be flagged for attention.

Step 3: Data logging and sample analysis

Assuming the sampling strategy is correct and the program has been designed based on sound reliability engineering goals; it is now up to the lab to ensure the sample provides the necessary information. The first stage is to make sure the sample, and subsequent data, is logged in the correct location so trend analysis and rate-of-change limits can be applied. While carelessness and inattentiveness on the part of the lab are inexcusable, it is incumbent on the end user to ensure the consistency of information that is logged and used for diagnostic interpretation including sending the sample immediately to the lab which has already been provided upfront with a new reference oil sample to compare with.

Once the sample has been properly set up at the lab, the actual sample analysis is next. This is an area where end users are definitely at the mercy of the lab and its quality assurance (QA) and quality control (QC) procedures. To overcome this, it again becomes the end user responsibility to ensure that the lab technicians have obtained any industry-recognized qualifications such as International Council for Machinery Lubrication (ICML's) LLA (Laboratory Lubricant Analyst) certification.

It is again the responsibility of end user to ensure that the lab has obtained any industry-recognized QA accreditation such as ISO 9001/ISO 14001 or ISO 17025 and has a well-designed QC program, with written and enforced procedures for each test to ensure uniformity in test procedures. It is also strongly recommended to visit a lab before selecting it to assess its overall commitment to quality.

Step 1 Program Design	• Machine selection • Select Oil analysis package • Ensure Program meets Reliability Goals
Step 2 Sampling Strategy	• Install sampling ports and valves at proper location • Sampling procedure • Sampling frequency • Use of clean and appropriate sampling bottles • Proper sample labeling and marking • Ensure correct and needed information is collected for each sample
Step 3 Data Logging & Analysis	• Sample forwarded to qualified laboratory • Ensure that the laboratory has effective QA/QC Procedures • New oil sample reference has been supplied • Testing as per agreed procedures and standards • Manage oil analysis information system
Step 4 Data Diagnosis	• Review and interpret Data • Use data with other CBM activities and maintenance records to make CBM decision
Step 5 Performance Tracking	• Track Oil Analysis Metrics • Cost Benefit Analysis • Compliance with reliability goals

Figure 25 Designing a World Class Turbine Oil Analysis Program

Step 4: Data diagnosis and prognosis

Diagnostic and prognostic interpretation of the data is perhaps the step where the most antagonistic relationship can develop between the lab and its customers. For some customers, there is a misguided belief that for a $10 oil sample, they should receive a report that indicates which widget is failing, why it is failing and how long that widget can be left in service before failure will occur. If only it were that simple!

The lab cannot be expected to know - unless it is specifically informed - that a particular component has been running hot for a few months, that the process generates thrust loading on the bearings, or that a new seal was recently installed on a specific component that is now showing signs of excess water in the oil sample.

Evaluating data and making meaningful condition-based monitoring (CBM) decisions is a symbiotic process. The end user needs the lab diagnosticians' expertise to make sense of the data, while the lab needs the in-plant expertise of the end user who is intimately familiar with each component, its functionality, and what maintenance or process changes may have occurred recently that could impact the oil analysis data. Likewise, evaluating data in a vacuum, without other supporting technologies such as vibration analysis and thermography, can also detract from the effectiveness of the CBM process.

Ultimately, it is the lab's job to explain its finding to the customer, and the customer's job to use these findings to make the correct maintenance decision, based on all available information, not just oil analysis data.

Step 5: Performance tracking and cost benefit analysis

Oil analysis is most effective when it is used to track metrics or benchmarks set forth in the planning stage. For example, the goal may be to improve the overall fluid cleanliness levels in the plant's turbine hydraulic oil by using improved filtration. In this case, oil analysis - and specifically the particle count data - becomes a performance metric that can be used to measure compliance with the stated reliability goals. Metrics provide accountability, not just for those directly involved with the oil analysis program, but for the whole plant, sending a clear message that lubrication and oil analysis are an important part of the plant's strategy for achieving both maintenance and production objectives. The final stage is to evaluate, typically on an annual basis, the effectiveness of the oil analysis program. This includes a cost benefit evaluation of maintenance "saves" due to oil analysis. Evaluation allows for continuous improvement of the program by realigning the program with either pre-existing or new reliability objectives.

SAMPLING AND TESTING SCHEDULE

One of the most important milestones of an oil analysis program is the sampling of the turbine oil. The way a sample is collected, the frequency, the accessories used and the procedures followed all dictate how informative the oil samples will be and, subsequently, dictates how beneficial the results will be.

The following questions should be answered when designing a turbine oil sampling program:

- Where is the best location to draw an oil sample to ensure the correct information is collected?
- What are the best tools for drawing a sample from a specific location?
- Who will be responsible for pulling the sample and how consistent will the sample be each time it's drawn from the specific location?

Using a poor sampling procedure just one time could result in:

- Changing oil unnecessarily
- Changing oil too late
- Changing oil too early
- Failure to recognize a machine failure in progress
- Unscheduled downtime

Sampling Port Location

Troubleshooting problems using oil analysis is greatly assisted by the installation of several sampling ports in various locations to isolate individual components. Isolating using multiple sample ports, gives an analytical edge for both discovering potential component failure and analyzing the root cause.

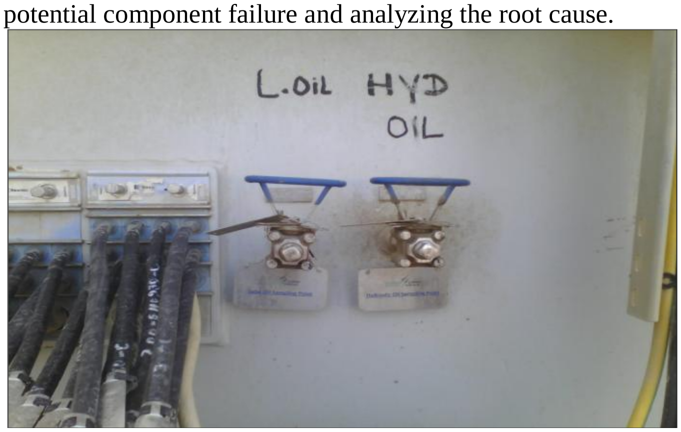


Figure 26 Primary Sampling Port for a GT Lube Oil & Hydraulic Oil

Figure 27 Secondary Sampling Port for Steam Turbine Lube Oil

Sampling Ports are classified into two categories:

- ***Primary Sampling Ports:*** The Primary sampling port is the location where routine oil samples are taken (figure 26). The oil fluid from this sample location is usually used for monitoring oil contamination, wear debris and the chemical and physical properties of the oil. Primary sampling locations vary from system to system, but are typically located on a single return line prior to entering the sump or reservoir.
- ***Secondary Sampling Ports:*** Secondary sampling ports can be placed anywhere on the system to isolate upstream components (figure 27). This is where contamination and wear debris contributed by individual components will be found.

Elements of an Effective Sampling Procedure

The process of building effective sampling procedures should begin with an assessment of the goals for oil analysis for each machine of interest. If the objectives end with a desire to schedule condition-based oil changes, the sample location and sampling procedure can be relaxed because the properties analyzed are homogenous. However, if the objectives include controlling contamination and detecting and analyzing wear debris, the sampling location and procedure become critical.

Sampling procedures will vary in form from organization to organization. At a minimum, the sampling procedure should include the following elements:

- Sampling Goal
- Sampling Location & Marking
- Sampling Frequency/Scheduling
- Material Requirements
- Sampling Method
- Potential Source of Interference
- Safety Considerations

Sample Markings

A sample should be properly marked. Markings should include at least the following information:

- Customer name
- Site or plant name
- Location (unit number, tank number, compartment number, and so forth)
- Turbine serial number (or other ID)
- Turbine service hours
- Oil service hours
- Date sample taken
- Type of oil sampled (lubricant ID)
- Sampling point/port ID
- Type of purification system (filters/centrifuge, and so forth), and
- Makeup (volume) since last sample was taken.

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 figure 28 are typical and should only be used as a guide. Refer to the past history, OEM instructions or other regulatory guidelines for lubricant testing requirements.

S. No.	Basis	Test	Test Method	Frequency
1.	Oil Condition	Color	ASTM D1500	Weekly
2.		Appearance		Weekly
3.		Viscosity	ASTM D445	Quarterly
4.		Wear Metal	ASTM D5185	Quarterly
5.		FTIR		Quarterly
6.		Acid No.	ASTM D664	Quarterly
7.		RPVOT	ASTM D2272	As required
8.		Demulsibility	ASTM D1401	As required
9.		Foam Test	ASTM D892	As required
10.		Air Release	ASTM D3427	As required
11.		Flash Point	ASTM D92	As required
12.	Oil Cleanliness	Particle Count	ISO 4406	Quarterly
13.		Water Content	ASTM D6304	Quarterly
14.		Rust Test	ASTM D 665	Annually

Figure 28 Ready reference for sampling and testing schedule

TIPS FOR DEVELOPING A SOUND TURBINE OIL CONDITION MONITORING PROGRAM

A successful turbine oil analysis highly depends on good sampling practices.

Sampling Basics

A good oil sample needs to:

- Maximize Data Density
- Minimize Data Disturbance

Three Key factors are of utmost importance for the collection of a good and representative oil sample:

- Location - Where?
- Consistency - Who & Procedure
- Correct Hardware/Fittings

The following ***Seven Points*** always need to be considered to accomplish a successful Turbine Oil Condition Monitoring Program:

- Time - When

- Frequency - How often
- Clean tools & sampling ports
- Drain dead oil out - 5 to 10 times of pathway volume
- Bottle Sample volume - 60 to 705 full
- Sample Labeling- Hours/Make up…
- Flushing sampling bottles, caps, tubes etc.

The analysis of a sample greatly depends on the quality of the sample itself (figure 29). A high-quality sample translates into one that is rich with data and free from noise.

Special precautions should be made when obtaining a sample from the machine reservoir for testing. It is vital to use a technique that will provide a representative sample. The sampling procedure must ensure that the technique used is consistent each time a sample is drawn to send to the laboratory. This will guarantee that tracking and trending values received from the laboratory are consistent and representative over time. In other words, the results will be meaningful.

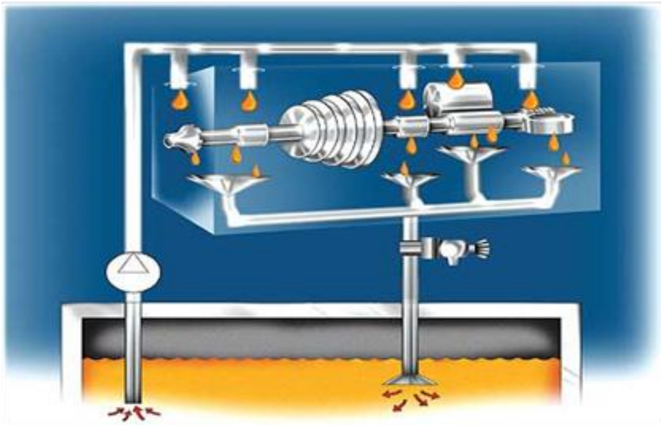


Figure 29 Oil Analysis data or garbage- Are you wasting money?

Oil Sampling Best Practices

When it comes to turbine oil sampling, the goals are always to choose a location that maximizes the density of the data in the sample bottle, and to choose a procedure that minimizes the disturbance of the data. The best practices for turbine oil sampling should include:

- Standard sampling procedures
- A representative sample
- Live Zone sampling i.e. Sampling while the machine is in service and at normal operating temperatures
- Upstream of filters, downstream of machine components
- A consistent sampling location
- Correct, safe and convenient sampling points
- A dedicated person is in charge of oil sampling, magnetic plug check and oil analysis data management
- Use of proper and flushed sampling valves, sampling devices, clean and appropriate sample bottles (figure 30)
- Good sampling frequency e.g. sampling prior to scheduled Preventive Maintenance (PM) program enabling to obtain oil analysis results well in time
- Proper sample labeling and marking
- Samples forwarded immediately to the lab

Figure 30 Typical examples of oil sampling devices

Garbage data

There are numerous sampling procedures commonly used that are far from best practice. Often these methods are used simply for convenience, in a misguided attempt to save valuable time, at the expense of valuable data and ultimately valuable equipment. Some good examples of such garbage data includes:

- Dead zone sampling
- Sampling cold systems
- Drain port sampling
- Changing sampling procedures
- Inadequate flushing
- Dirty sampling pathway/hardware/bottles
- Sampling after oil change
- Cross contamination of sampling devices
- Sampling on dusty or rainy day
- Waiting days or weeks before sending samples to lab

A self examination check list of Oil Sampling Best Practice is shown in figure 31.

Items	Check
Standard Sampling Procedures?	
Sampling Tags on your machines?	
Representative and Consistent sampling locations	
Correct, safe and convenient sampling valves or points?	
Sampling Timing? (From running machines, hot/warm oils, etc.)	
Sampling Tools?- Live sampling valves, central sampling points, correct vacuum pump sampling procedures	
Clean Operation?-Clean tools, tubing, bottles, hands, rags etc.	
Preparation prior to sample-Labeling before sampling, waste bottles, permanent pens, filling sample sheet properly, collecting oil top-up data, filter change etc.	
Sampling 2-3 days prior to PM	
Dedicated people for sampling	

Figure 31 Self examination check list of oil sampling best practice

LOGGING, TRENDING AND INTERPRETATION OF TEST DATA ALONG WITH RECOMMENDED ACTIONS:

It is very 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 or replacement oil), possible intermixing of oils, newly installed parts, and recent system inspections. Guidelines for warning levels are provided in Appendix A. However, oil supplier guidelines or OEM guidelines, or both, supersede Appendix A. These warning levels should also be considered with trending information.

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 taken when necessary. Such action must be based on a correct interpretation of test results (see Appendix A), 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. Re-sampling and retesting is recommended before proceeding. Actions recommended by the oil supplier or OEM, or both, supersede those in Appendix A.

SUMMARY

This paper has covered the basics of common turbine oil analysis tests and their significance. While the results of these tests are a powerful maintenance tool, they are useless <u>if not monitored and acted upon.</u> A successful turbine oil analysis program will be one where the test data and analysis is coupled with the maintenance department’s knowledge and expertise to provide the most effective maintenance practices.

Knowledge of plant specific turbine oil and its limitations will set the stage for years of reliable service. Keys to this knowledge include having the right tools for the job, and a solid understanding of lube oil analysis for new turbine oil evaluation and in-service oil condition monitoring. By following a few simple rules, like keeping the oil cool, dry and clean and monitoring with regular, routine oil analysis, turbines oils should provide many years of continued service.

CONCLUSIONS

- In-service Turbine Oil monitoring and analysis has achieved significant savings in oil life extension. Even greater savings have resulted from proactively detecting potential equipment problems caused by poor oil quality.

- Trends should be monitored when measuring turbine oil conditions. If a significant change occurs in a sample, it should be retested immediately to determine the validity of the sample and/or the testing procedure.

- Limits are used as guidelines only. Lubricant suppliers and OEMs should be consulted to establish specific limits by lubricant and equipment type. The use of many different sources, both internally and externally, helped develop the limits presented in this tutorial. Limits are based on oil and equipment type.

- Many companies use oil analysis and rely on the laboratory for recommendations. The more progressive plants understand oil analysis and the meanings of key tests and limits as it relates to their equipment. In addition, they also thoroughly evaluate the laboratory used to perform such testing. These plants also use results to make decisions on maximizing oil life without compromising equipment.

- Turbine oils are normally condemned because of oxidation and contamination i.e. when both water and particulates cannot be removed economically.

- Both caution and critical limits for industrial turbine oils are presented in this paper. Industrial turbine oils can often be reconditioned by removing contaminants through centrifuging, filtration and vacuum dehydration. Caution limits give early warnings to potential problems, allowing the plant to plan a more accurate reconditioning schedule.

- Additive depletion, which is difficult to detect, is a less common reason for condemning oil. Oxidation inhibitors in turbine oils deplete after many years. Because these inhibitors are ashless, their depletion is measured by using the RPVOT test that assesses the remaining useful oxidative life of the oil.

- Oxidation is normally measured in industrial oils by TAN, RPVOT and the viscosity increase. New oils have an initial TAN, therefore, the increase over the initial value measures oxidation.

- FTIR is another effective method to measure oxidation, but only if referenced to a new oil sample. It cannot be used for synthetic oils containing esters because oxidation peaks and ester peaks are at the same frequency (wave number). Natural gas engine oils use FTIR as the primary test to measure oxidation and nitration.

- Many different tests have been discussed, but onsite observance of oil appearance is still important and must not be neglected.

- It is to be remembered that no oils in a drum are delivered clean. Baseline values for new oil when delivered from the oil supplier have to be established from which deviations in trends can be easily monitored.

APPENDIX A

S.No	Test	Warning Limit	Interpretation	Action
1.	**Color**	Unusual and darkening rapidly	Indicative of: a) Contamination b) Excessive degradation	Determine cause and rectify
2.	**Appearance**	Hazy	Oil contains water or solids, or both.	Investigate cause and remedy Filter or centrifuge oil, or both
3.	**Viscosity (ASTM D445)**	+20%/-10% from original oil viscosity	Oil is: a) Contaminated or b) Severely degraded c) Higher or lower viscosity oil added	Determine cause. If viscosity is low, determine flash point. Change oil if necessary.
4.	**Cleanliness (ISO 4406)**	Particulates exceed accepted limits.	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.
5.	**Total Acid Number (TAN) increase over new oil. (ASTM D664)**	0.1 – 0.2 mg KOH/g	Above normal degradation for steam turbines up to 20,000 hrs oil life and gas turbines up to 3,000 hrs oil Life. Possible causes are: a) System very severe b) Anti-oxidant depleted c) Wrong oil used d) Oil contaminated	Increase testing frequency and compare with RPVOT data. Consult with Oil Supplier for possible re-inhibition.
		0.3 – 0.4 mg KOH/g	Oil at or approaching end of service life. Point c) or d) above may also apply.	Look for signs of increased sediment on filters and centrifuge. Check RPVOT and FTIR. If RPVOT less than 25% of original oil, change the oil. If oil left in system, increase test frequency.
6.	**RPVOT (ASTM D2272)**	Less than half value on original oil.	Above-normal degradation for steam turbines up to 20,000-hr oil life and gas turbines up to 30,000-hr oil life.	Investigate cause. Increased frequency of testing.
		Less than 25% of original value	Together with high TAN, indicates oil at or approaching end of service life.	Resample and retest. If same results, consider oil change.
7.	**Water Content (ASTM D6304)**	Exceeds 0.1%	Oil contaminated – possible water leak.	Investigate and remedy cause. Clean system by centrifuging. If still unsatisfactory, consider oil change or consult oil supplier.
8.	**Foam Test, (ASTM D892 Sequence 1)**	Exceeds tendency of 450, stability of 10.	Contamination Anti-foamant depletion, In new turbine, oil absorption of residual rust preventive.	Determine cause and remedy. Consult oil supplier regarding re-inhibition.
9.	**Rust Test (ASTM D 665A)**	Light fail	000-hr service: is wet or dirty or both, is not maintained properly ater drainage neglected, centrifuge rating). 000-hr oil service: additive depletion in wet system.	Investigate cause and make necessary maintenance and operating changes. Check Rust Test. Consult oil supplier regarding inhibition if result unchanged. Consult Oil supplier regarding re-inhibition
10.	**Flash Point (ASTM D92)**	Drop of 17°C (30°F) or more compared to new oil	Probable contamination.	Determine cause. Check other quality parameters. Consider oil change.

NOMENCLATURE

AES	=	Atomic Emission Spectroscopy
API	=	American Petroleum Institute
ASTM	=	American Society of Testing and Materials
CBM	=	Condition Based Maintenance
EP	=	Extreme Pressure
FMEA	=	Failure Mode and Effect Analysis
FTIR	=	Fourier Transform Infrared Spectroscopy
ICML	=	International Council for Machinery Lubrication
ISO	=	International Standard Organization
KF	=	Karl Fischer
LLA	=	Laboratory Lubricant Analyst
MIL	=	Military Specifications
MTBF	=	Mean Time Between Failure
NAS	=	National Aerospace Standard
OEM	=	Original Equipment Manufacturer
PAO	=	Poly Alpha Olefins
QA	=	Quality Assurance
QC	=	Quality Control
PM	=	Preventive Maintenance
RCM	=	Reliability Centered Maintenance
RPVOT	=	Rotating Pressure Vessel Oxidation Test
TAN	=	Total Acid Number
TOST	=	Turbine Oil Oxidation Stability
VG	=	Viscosity Grade
VI	=	Viscosity Index

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