Laboratory tests for steam and gas turbine oils

Predicting turbine performance

Predicting the operational performance of your turbine based on lube oil analysis can have a positive impact on unit reliability and maintenance metrics. There are many testing options for both gas and steam turbines—to provide data about turbine performance and oil condition—and it is important to understand not only the tests available, but also how those tests complement each other to provide a complete picture of your system and oil condition.

As with all condition monitoring, turbine oil testing provides the best data when trended over time to allow for more meaningful data interpretation. Proper interpretation can allow planning of potential corrective maintenance activities like improved filtration or water removal.

This document will provide you with an overview of the available tests to monitor your system and oil condition in steam and gas turbines, as well as recommended test slates and condition-monitoring intervals.

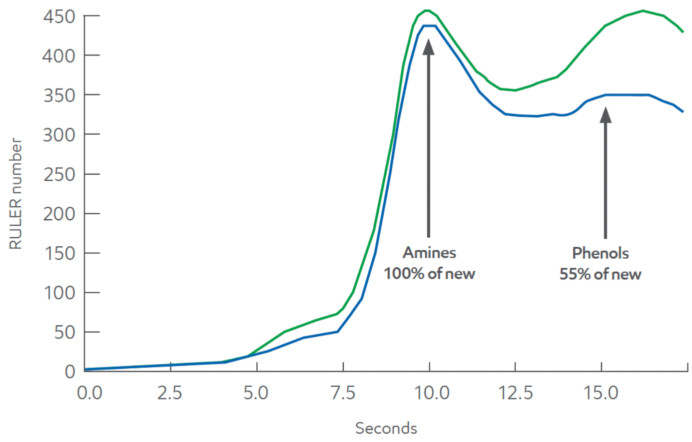
Tests for varnish prediction—gas and steam turbines

Gas turbine trips or no-starts caused by varnish in system hydraulics have created a demand for in-service lubricant varnish testing. Most turbine oil varnish issues take place in gas turbine hydraulic circuits when the hydraulic system and bearings share a common reservoir. Different varnish tests are growing in industry acceptance and can, if used properly, provide meaningful data. However, varnish prediction tests should be viewed as a whole, taking into account all the tests in the slate. Comprehensive oil analysis, done in conjunction with visual equipment inspections and knowledge of oil operating hours, will offer the most accurate condition assessment.

If a varnish prediction test is at a caution level, we recommend the test data be corroborated by visual component inspections with photo documentation and lubricant service hours. Lack of a corroborating component inspection can lead to unnecessary or insufficient maintenance. Note that the testing suggested in this document is appropriate for API Groups I, II, III, and IV steam and gas turbine oils. Some of these suggested tests will offer misleading results in testing of hydraulic oils or API Group V, aeroderivative oils.

ASTM D6971—Linear Sweep Voltammetry, commonly known as RULER®
Remaining Useful Life Evaluation Routine (RULER) is governed by ASTM D6971—Standard Test Method for Measurement of Hindered Phenolic and Aromatic Amine Antioxidant Content in Non-zinc Turbine Oils by Linear Sweep Voltammetry.

Figure 1: Linear Sweep Voltammetry.
Comparision of new oil (green line) to in-service oil (blue line)



RULER testing compares antioxidant levels of new oil versus the in-service sample by measuring additive content by voltage differential **(Figure 1)**. Understanding antioxidant reserve in turbine oils can be helpful in predicting end of oil life and may provide insight on varnish formation. Many turbine oil antioxidant packages have a mixture of amine and phenolic antioxidants, which vary by type and blend ratio. Therefore, it is very important that the testing lab has an appropriate reference sample from which to measure the change in antioxidant levels.

In many higher-temperature applications, like gas turbines, the phenol concentration will decline more rapidly than the amine concentration. The phenol may convert to an intermediate antioxidant, which can either further stabilize the amine or volatize, so both phenol and amine peaks need to be measured to determine how much antioxidant remains.

The caution limit for RULER is at 25 percent of the remaining antioxidant, which is typically the amine.

Antioxidant trending through RULER offers reduced or misleading value in mixed or commingled reservoirs with multiple formulations.

Test frequency is dependent on risk tolerance and can range from quarterly to annually.

ASTM D7843—Membrane Patch Colorimetry (MPC) test method
Color and light blockage from lubricant deposits on a membrane patch can indicate the presence of varnish in the oil. Membrane Patch Colorimetry (MPC) testing measures visible light wave absorbance as a Delta E (change in energy) measurement, which can start at 1 and darken to 200-plus. Some labs may use this Delta E value to generate a lab-specific varnish rating that is scaled from 1 to 100.

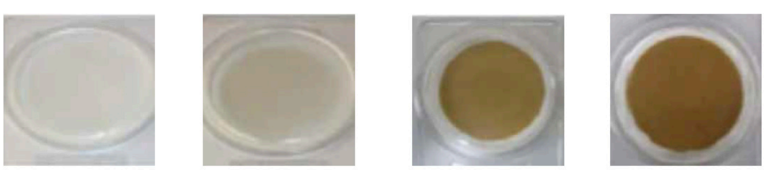
As with all varnish data, the interpretation should be application- and oil-specific and confirmed by visual inspection **(Figure 2)**. Test frequency is dependent on risk tolerance and can range from quarterly to annually. MPC tests may be biased against some antioxidant chemistries that produce dark deposits, so care must be taken when assigning specific varnish ratings that have not been formally standardized.

Ultracentrifuge Rating—ExxonMobil Method
Ultracentrifuge Rating (UC) was developed by ExxonMobil to help identify finely dispersed or suspended particles in the oil. The primary use of this test is to give an early indication of deposit precursors in the oil.

The subject oil sample is centrifuged at 17,500 rpm for 30 minutes. At the end of this period, the test tube is drained and the remaining sediment is rated against a standard **(Figure 3)**.

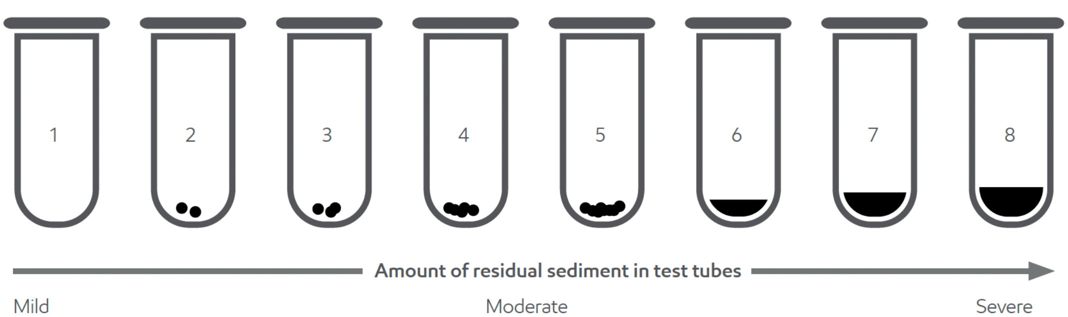
The results of the test are reported on a scale of 1 to 8, where an 8 indicates the highest amount of residual sediment. A result above 4 may be cause for concern that the oil has the potential to lay down performance-robbing deposits in the system. Test frequency is dependent on risk tolerance and can range from quarterly to annually.

Figure 2: MPC membranes photographed after filtration and corresponding MPC Delta E ranges
Caution at MPC Delta E at 40



Delta E <15 | Delta E 15–30 | Delta E 30–40 | Delta E >40

Figure 3: Ultracentrifuge visual sedimentation rating scale



Suitability for continued use—steam and gas turbine tests

The following are key tests used to determine whether a turbine oil is suitable for continued use.

ASTM D2272—Standard Test Method for Oxidation Stability of Steam Turbine Oils by Rotating Pressure Vessel

The Rotating Pressure Vessel Oxidation Test (RPVOT) was developed for use with in-service oils to warn of a loss in oxidation stability. Oxidation is driven by heat and exposure to contaminants such as water. As a turbine oil degrades, it forms weak organic acids and insoluble oxidation products that may adhere to governor parts, bearing surfaces, reservoir walls, and lube oil coolers. A severely oxidized turbine oil may form varnish on hot bearing surfaces that retard heat transfer and can overheat journal bearings. In addition, severely oxidized oils can foul turbine control elements and heat exchangers.

This accelerated oxidation test is an industry standard for identifying oxidation stability decay of in-service turbine oils. ASTM D4378 (Standard Practice for In-Service Monitoring of Mineral Turbine Oils for Steam, Gas, and Combined Cycle Turbines) identifies an RPVOT decline to 25 percent of the initial new oil RPVOT value with an increase in Acid Number (AN) as a warning limit. Many turbine OEMs simplify this metric by using the 25 percent of initial RPVOT without reference to AN increase. Waiting for the accompanying increase in AN can present additional risk if the turbine oil cannot be replaced in a timely manner. Some OEMs suggest a 100-minute minimum RPVOT in lieu of tracking RPVOT reduction. It should be noted that the RPVOT test is designed to determine a lubricant's suitability for continued use and is not intended as a predictor of new oil performance.

In steam and gas turbines, RPVOT testing should be conducted on an annual basis. Often the testing is conducted the month prior to a scheduled outage. An increased test frequency is recommended as the turbine oil approaches 25 percent of its initial RPVOT value.

ASTM D445—Standard Test Method for Kinematic Viscosity of Transparent and Opaque Liquids

Viscosity is the most important characteristic of a turbine oil because of the tight clearances in journal and thrust bearings. Turbine blade clearances are critical to power plant efficiency and reliability. Lubricant viscosity directly impacts blade clearances. Changes in oil viscosity can result in unwanted rotor positioning, both axially and radially. Axial movements will directly impact turbine blade efficiency and can lead to blade damage. Radial movements caused by changes in viscosity can result in "oil whirl" or "oil whip," where the rotor does not settle into one radial position. Vibration testing often identifies oil whirl or oil whip. Unless the oil has been contaminated or severely oxidized, viscosity should remain consistent over years of service.

A plus or minus 5 percent change from the initial oil viscosity is a suitable warning limit. Testing for viscosity should be conducted on a quarterly basis, at a minimum.

ASTM D6304—Standard Test Method for Determination of Water in Petroleum Products, Lubricating Oils, and Additives by Coulometric Karl Fischer Titration

Or

ASTM D7546—Standard Test Method for Determination of Moisture in New and In-Service Lubricating Oils and Additives by Relative Humidity Sensor

Testing for water is important to minimize the risk of possible undetected turbine oil oxidation and rust formation. Equipment rust often leads to iron oxide particle formation that can break off and cause abrasive wear in bearings. Excessive water can also alter an oil's viscosity (up or down, depending on conditions). Water in turbine oil in warm storage tanks can promote the spread of microbial growth that will foul system filters, small-diameter gauges, and transducer line extensions.

Free water is water that is not soluble in the oil at a given temperature. It is this free water that will lead to corrosive damage of metal parts. When a turbine oil has cooled to ambient conditions, dissolved water may come out of solution as free water, so care must be taken to minimize water content (to protect both the equipment and the turbine oil).

The ASTM D4378 recommended water-warning limit is 200 ppm. Some end users may opt for a more conservative level of 100 ppm. The approximate free water saturation point at 20oC (70oF) is 100 ppm, so water contents above 100 ppm at 20oC (70oF) will start to form free water. In hydrogen-cooled generators, an upper limit of 250 ppm should be maintained to minimize the potential for stress corrosion cracking of generator rotor retaining rings.

Particularly for steam turbines, testing for water should be conducted on a quarterly basis, at a minimum.

ASTM D664—AN—Standard Test Method for Acid Number of Petroleum Products by Potentiometric Titration

Sharp increases in total AN may indicate contamination or a severely oxidized oil. Note that AN measurement by ASTM D664 (potentiometric titration) is used more widely than ASTM D974 (color titration) for in-service oil analysis because darker oils are more difficult to accurately test by color titration.

ASTM D4378 offers guidelines of 0.3 to 0.4 mg KOH/g above the initial value as an upper warning level. Many oil analysts view an upward movement in AN as small as 0.1 as worthy of concern. Note that AN has fairly poor reproducibility from lab to lab, so AN results should be viewed in the context of the other results.

Testing for AN should be conducted at least on a quarterly basis.

ASTM D1401—Demulsibility—Standard Test Method for Water Separability of Petroleum Oils and Synthetic Fluids
Water shedding (demulsibility) characteristics are important to lube oil systems that have direct contact with water. This is particularly true for steam turbines where some level of gland seal water leakage is inevitable. The ability of the oil to shed water will have a direct impact on its long-term oxidative stability and equipment rust. Turbine oil demulsibility can be compromised by excessive water contamination or the presence of polar contaminants and impurities, as found in most engine oils. As little as 11 liters (3 gallons) of engine oil contamination in 22,700 liters (6,000 gallons) of turbine oil can negatively impact the demulsibility of a turbine oil.

Demulsibility is tested using ASTM D1401, in which a known volume of oil (40 mL) is mixed with water (40 mL), and the time it takes for the two fluids to separate is measured in minutes; the faster the separation, the better the demulsibility.

The ASTM D4378 demulsibility limit is greater than 3 mL of stable emulsion and/or less than 36 mL water at 60 minutes. New oil guidance (ASTM D4304) and many steam turbine OEM specifications suggest a maximum time of 30 minutes to achieve an emulsion of 3 mL or less. The impact of oil demulsibility depends on the residence time of the oil in the system and anticipated levels of water contamination. An oil can show poor demulsibility performance in the lab, but with sufficient residence time, the system oil may still shed water at an acceptable rate that does not impact turbine oil performance. Small sumps with lower residence times require better demulsibility performance than larger sumps. For gas turbine applications, demulsibility performance is not a required attribute of the oil due to the heat generated by the turbine. Testing for demulsibility should be conducted on an annual basis if the lube oil system is exposed to water.

ASTM D5185—ICP elemental metals—Standard Test Method for Determination of Additive Elements, Wear Metals, and Contaminants in Used Lubricating Oils and Determination of Selected Elements in Base Oils by Inductively Coupled Plasma Atomic Emission Spectrometry (ICP-AES)
Inductively Coupled Plasma (ICP) metals analysis offers insight on additive, wear, and contamination levels. ICP metals testing looks at a narrow size spectrum of particles below 8 microns. This is suitable for oil analysis, as catastrophic failure typically starts as submicron wear. Generally speaking, additive metals should be maintained at levels above 50 percent of new oil condition. Wear metals like iron, copper, and tin should be alarmed at levels of 5 ppm or higher when the sample is pulled from the reservoir. Bearing-specific drain samples should have lower wear metal limits. Contaminants like silicon should be kept below 25 ppm.

Testing for metals should be conducted on a monthly or quarterly basis.

ASTM D7414—Fourier Transform Infrared measurement of oxidation (differential method for oxidation)
ASTM D7414 measures oxidation absorbance peaks as an indicator of oxidation formation using FTIR. This measurement tests for oxidation byproducts as indicated by carbonyl peaks detected between 1800 and 1660 cm-1 (typically centered around 1709 cm-1).
Figure 4 shows a distinct lack of a carbonyl peak in this region, as would be expected from oil that has not oxidized in use. Differential FTIR absorbances measured as a peak height maxima between 1800 and 1660 cm-1 at 4 or above should be cautioned.

Figure 4: This is a typical FTIR scan
We look for oxidation peaks between 1800 and 1660 cm^{-1}, a lack of which leads to a low differential value, indicating low oxidation

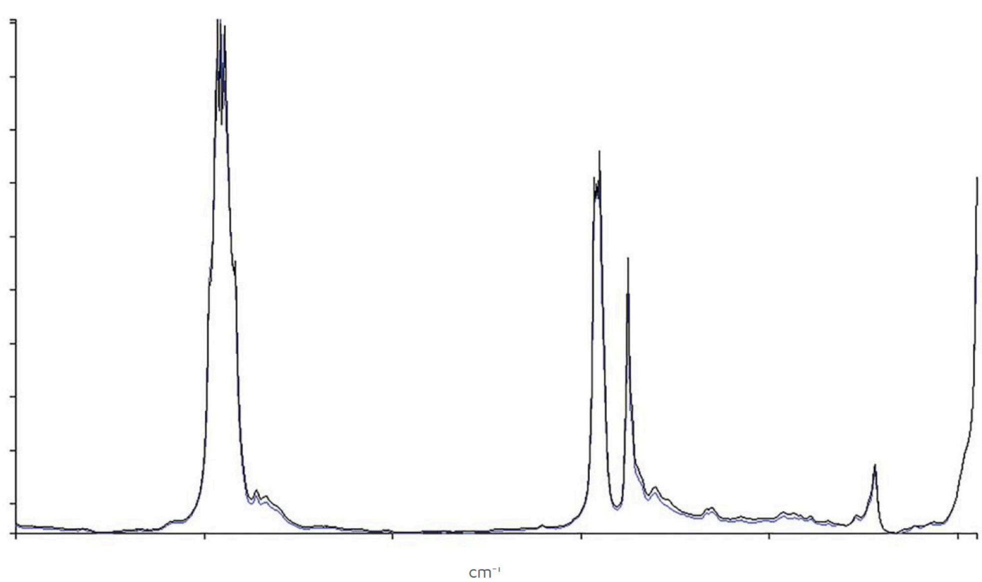
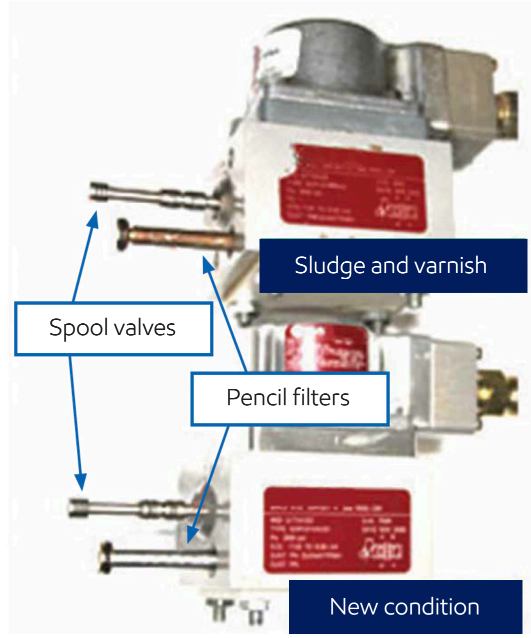


Figure 5: Photos documenting condition of varnish-sensitive parts

Valve pencil filters

New condition

Sludge and varnish



ISO 4406—Particle count
Particle Counting and ISO Cleanliness ratings define the concentration of particles in the oil and relate this back to the ISO Cleanliness scale. The results are reported as the number of particles greater than 4 microns/6 microns/14 microns per mL of fluid.

The ISO Cleanliness Code relates the number of particles per mL to a logarithmic scale with a code number for each range. A typical result would look like 18/16/13, where 18 means there are 1,300 to 2,500 particles per mL greater than 4 microns in size, 16 means 320 to 640 particles per mL greater than or equal to 6 microns in size, and 13 means 40 to 80 particles per mL greater than 14 microns in size.

Particle counts are subject to a wide range of variability due to sample preparation, oil formulations, contamination of the sample container, and location and method of sampling. There are also differences in the equipment used to measure particle counts between light dispersion techniques and filter pore blockage methods. Care should be taken to ensure that the samples used for particle counts are representative and consistent. The particle count results are only good as a relative measure of contamination, and no ASTM standard exists for this test. Ultimately, however, particle count does give a good indication of overall system cleanliness.

The oil wedge formed in a journal bearing may be 10 to 20 microns thick with a journal-to-bearing clearance of 200 microns, and hydraulic servo-valve clearance can be 2 to 5 microns. These clearances dictate the need for clean oil. Excessive bearing wear and servo-valve wear can result if proper cleanliness standards are not maintained.

Many turbine OEMs offer oil cleanliness guidance of ISO 18/16/13 (NAS 1638 class 7). If the turbine oil is also used as the hydraulic control fluid, the recommendation ISO Cleanliness is often 16/14/11 (NAS 1638 class 5). Some turbine OEMs that publish ISO Cleanliness guidelines still use the older two-code report method that omits the first Cleanliness Code, the 4-micron patch rating.

Testing for ISO Cleanliness should be conducted on a monthly or quarterly basis.

ASTM D892—Foam—Standard Test Method for Foaming Characteristics of Lubricating Oils
It is common for a turbine oil reservoir to have some foam on the oil's surface, but there should be surface areas with no foam where larger bubbles can break. A turbine oil sample may test at elevated foam levels, but excessive field foaming issues are rare. Foam levels that continue to rise, resulting in reservoir overflow or faulty tank level indication, should be addressed.

ASTM D892 testing is conducted at three temperatures: Sequence 1 at 24°C (75°F), Sequence 2 at 93.5°C (200°F), and then cooled back to Sequence 3 at 24°C (75°F). Data is reported in mL as tendency and stability for each sequence. Foam tendency is the foam volume measured in a graduated cylinder after five minutes of blowing air through the lube oil sample. Stability represents the volume after 10 minutes of settling time has elapsed. A foam stability of 0 mL is a good indication that foam bubbles are breaking and the turbine should not experience excessive foam during normal operation. Of the two measurements, tendency and stability, it is more important to maintain good stability versus tendency. In an oil analysis cost- savings measure, sometimes only Sequence 2 testing is conducted because 93.5°C (200°F) approximates equipment operating temperatures.

ASTM D4378 offers warning limits of tendency 450 mL with a stability of 10 mL for ASTM D892, Sequence 1. It should be noted that ASTM D892 foam test reproducibility is fairly poor. A tendency measurement of 450 mL could be as high as 600 mL or as low as 300 mL at a different lab.

When addressing foam problems, cleanliness, contamination, or mechanical causes should be investigated before considering field defoamant readditization. Improper readditization can result in an even greater problem with increased air entrainment, more excessive foaming, or additive fallout. Contamination is a leading cause of foam, so ISO Cleanliness and ICP metals should also be tested. Locating the lube oil pump suction near the reservoir bottom minimizes the potential for foam to be supplied to a bearing.

Testing for foam should be conducted only when foaming presents an operational problem and for product compatibility testing.

Interpretation recommendations

The turbine oil's overall condition can be assessed from a combination of oil analysis, visual equipment inspection, and knowledge of oil operating hours. Annual photo documentation (see Figure 5) of varnish-sensitive parts should be part of the turbine oil assessment.

Lubricant analysis options

Turbine oil analysis options should be assembled in a manner that provides pertinent, cost-effective information. Specific turbine oil analysis options for routine trend analysis and advanced analysis for suitability for continued use or varnish prediction are described below. Ensure oil operating hours are included in sample information provided.

	Routine trend analysis	Varnish prediction analysis	Suitability for continued use
Frequency	**Monthly/quarterly**	**Quarterly/annually**	**Annually**
Viscosity—ASTM D445	✔	✔	✔
Water—by Karl Fischer Titration ASTM D6304 (or D1744) or by relative humidity ASTM D7546	✔	✔	✔
FTIR, Oxidation—ASTM D7414	✔	✔	✔
Acid Number—ASTM D664	✔	✔	✔
ISO Cleanliness Code 4406	✔	✔	✔
Ultracentrifuge (UC)—ExxonMobil method	✔	✔	✔
Linear Sweep Voltammetry (RULER)—ASTM D6971		✔	
Membrane Patch Colorimetry (MPC)—ASTM D7843		✔	
RPVOT—ASTM D2272			✔
Demulsibility—ASTM D1401 (if exposed to water)			✔
Foam—ASTM D892 (if warranted)			✔
ICP Elemental Metals—ASTM D5185	✔	✔	✔

ExxonMobil interpretation guide

This table is provided for general guidance. Interpretation should be application specific and confirmed through visual inspection and lube oil operating hours.

Test name		Reference	Description	Warning level*
LSV—Linear Sweep Voltammetry (aka RULER)	**AOx_1 % (Amine)** **AOx_2 % (Phenol)**	ASTM D6971	Measures individual AOx concentration in oil compared to a new oil reference (%)	Less than 25% remaining of the primary antioxidant (AOx_1)
MPC—Membrane Patch Colorimetry		ASTM D7843	Measures color change of a filter patch due to varnish vs. clean patch as energy change (ΔE)	40 or greater
UC Rating—Ultracentrifuge		Internal method	Measures the amount of insolubles in oil (scale 1–8)	4 or greater
FTIR (Oxidation)—Fourier Transform Infrared		ASTM D7414	IR Spectroscopy to measure oxidation absorbance peak	4 or greater
AN—Acid Number		ASTM D664	Measures oil acidity level (mg KOH/g)	0 or greater
RPVOT—Rotating Pressure Vessel Oxidation Test		ASTM D2272	Measures oxidation stability decay of in-service oil (minutes)	Less than 25% of new oil value

Implementation of a well-designed oil analysis program requires equipment knowledge and awareness of potential suffering points. Once implemented, proper interpretation combined with an understanding of potential corrective actions should have a positive impact on uptime and maintenance metrics.

For more information on Mobil℠ industrial lubricants and services, please contact your local ExxonMobil representative or the ExxonMobil Technical Help Desk at 1.800. Mobil25 or visit mobilindustrial.com.

* May be Caution or Alert, depending on data. Monitor system to take appropriate corrective action.