http://www.stle.org/resources/articledetails.aspx?did=1815 - Maintenance of Fire-Resistant Fluid (Phosphate Ester) EHC Turbine Governing Control System in a Nuclear Power Plant

http://www.stle.org/resources/articledetails.aspx?did=1816 - Reducing the Varnish Tendency of a Group II Base Oil by Increasing the Solvency

https://www.stle.org/resources/articledetails.aspx?did=1720 - Interpreting Results for the New ASTM Standard for Varnish Potential

http://www.stle.org/resources/articledetails.aspx?did=1814 - Turbine Oil Selection

http://www.youtube.com/watch?v=NG-iWUgpvcE - oil filters

What should be the moisture limit for turbinol-32 for a 300MW turbine? --- **Petr Vavruch:** 0.1%, see: http://www.mobilindustrial.com/ind/english/files/tt-turbine-oil-condition-monitoring-training-guide.pdf but see also Appendix 2. --- **Alessandro Paccagnini, CLS / MLT-I:** Latest version of ASTM D4378 specifies a limit of 200 ppm for both steam and gas turbine mineral lubricants. This makes much sense to me: older limits such as 0.1% are way too high and well beyond saturation limit.

http://www.mobilindustrial.com/ind/english/files/tt-turbine-oil-condition-monitoring-training-guide.pdf

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Problem with the solubility of oxidation products in turbine oil at low temperatures

Elena Yolova Lubricants Expert at "SGS Bulgaria"Ltd

In recent times my clients have a problem with the solubility of oxidized products in turbines and hydraulic oils - at operating temperatures (60-80 C) are dissolved, but in stoppage (i.e. temperature below 25 C) become insoluble and begin to deposit on working surfaces. It is a great problem with the hydraulic piston pumps.

It does not matter the type of turbine (manufacturer or gas/steam/etc) or working hours - I see it in every case.

Usually turbine and hydraulic oils are produced by base oil Group II and quality is according ISO 8068 for turbine oils and ISO 11158 for hydraulic oils; viscosity grade VG32 or VG46.

Maintenance is according ASTM D 4378 (for turbine oils) and ASTM D 6224 (for hydraulic oils).

Ghasem Shilati Technical Manager at Naham Pala Engineering CO.

There is no single cause and remedy for all varnish problems. Few technologies are available in marker for varnish mitigation along with many claims, introducing "miracle based" products for varnish removal.
The best solution is still preventive solutions.
There are some main causes of varnish contamination including micro-dieseling, molecular electrostatic discharge, severe mechanical friction, oil ageing and so on. All of them can be summarized in one phrase. That is "HOT SPOTS". Thus look for hot spot which is main source of oil degradation and varnish contamination.

Jean-Michel Demaret Technical Expert , Concentrating Mill Maintenance at PT Freeport

Hello Elena. What you describe is what I call sludge. Once the oil has stopped moving (and bonds weaken) gravity takes over. However it will take hours or days for these heavier molecules to reach the bottom. The best time to partially drain the bottom of a tank and get the impurities out is when the oil is cold. If the bottom of the tank is slanted it helps, if it is flat you may have to use an industrial type of vacuum cleaner (suck the bottom of the tank out, filter it and back in the tank). Do not expect to move the remote sludge far from the drain point when the bottom of the tank is flat, by just opening the drain valve.
My impression is that the more additives you have in the oil, the more sludge you get (more sludge in hydraulic). Some additives like ZDDP have a tendency to turn in sludge once they are not active anymore. All additives are not equal to prevent the creation of sludge or varnish.
As Ghasem pointed out, hot spots are the problem. You can have the bulk tank at the right temperature, if there is a hot spot at the bearing or at the pump, additives react and sludge is created. In your case Elena your customers may gain in using a Group II zinc-free oil, if it is not already the case. Or he should try to reduce the hot spots which is not as easy.

Damanik Ramidi   ISO VA II,MLTI,MLAII Reliability & Condition Monitoring

Varnish phenomena and "Dual Course Oxidation". Varnish is resulted from oxidation, while oxidation is irreparable. Oxidation is chemical s involving oxygen.

Dual course of oxidation is firstly: increasing ACID NUMBER the reaction will form acid and lead to corrosion, and secondly: increasing VISCOSITY the reaction will form soluble long chain molecules, insolubles long chain molecules, sludge and tars, and finally VARNISH.
At low temp, carbon and oxide migrate and condense in insolubles.

How to remove Varnish, electrostatic filtration is most of effective, while others BCA, Compressed Cellulose, Ion-Exchange resin.

Norbert Czubak   Company Owner of Lube Expert

Heavy oxidized oil that is still "able" to keep polymerized particles is near the point of varnish (one of the last stage) of oxidation. After that, (maybe also due to temperature decreasing) soluble oxidation products will condense and polymerise together, forming higher molecular weight, long chain particles, referred to as oligomers. Depending concentration, chemistry and temperature (what you've seen), the oligomers can reach the saturation point of turbine oil. When solubility point has been exceeded, the contaminants will precipitate out of solution and form insoluble particles. Dark, sticky residues with high molecular weight, that in most of the cases are precipitated near bottoms of oil tanks and also places where they stay. This also because these particles are polar and have high dipole moment.
As for keeping them soluble, well...it depends whether you have organic degradation (base oil itself), or non-organic (depletion of additives). Moreover varnish is also catalyst for further oxidation. So, it's better to keep it out from the system. The best way out is to remove them by electrostatic or resin-cellulose filters.
During exploitation of turbine oil, you can measure level of antioxidant (e.g. by FTIR method), that mainly are alkylated diphenylamine and phenolics. When these additives are gone, or level of them in the oil is low, then you can expect incoming troubles.

Dennis Behr   Regioleider bij Oliveira International

I'm following the discussions about the varnish phenomena for a couple of weeks now and based on my experience my opinion is that it's a part of the oxidation process also and that some companies make good profit on this so could varnish phenomena without proper oil analyses (for MPC and Ruler) by an independent lab.

I'm not saying that varnish doesn't exists, but because of ignorance, you believe you have a huge problem. The process of removing varnish with a unit they deliver will take months for a result. There is a company that says they have a patent on an additive in combination with a unit the deliver, but in your case only the unit is needed. My biggest problem is that the units are delivered and identical, but painted and have another name; from one of the leading filtration manufactures; only 3 times more expensive. I understand that what I am saying will shock everybody.

My advice is to hire/buy a mobile micro-filtration for example tank 20000 l with a unit 400 l/min. In my case parallel filter elements 5-3-1 micron will have much more results and on short notice if you had a contamination problem and a quick response has to be made. The 20000 l must be drained and filtered and tank must be cleaned. More important is the whole system need to be flushed. In this case stat free elements in-line filters were placed and a permanent micro-filtration unit 2 micron 60 l/min.

Air breathers and vapour separator should be inspected on proper working.

Instead of being busy trying to understand varnish, think about the oxidation proces that accelerated by hot spots is also my opinion. Something mechanical is causing this proces to be accelerate. Looseness, alignment, wrong bearings. I had little experience with this, but was forced to look into it and was lucky i had resources as an independent lab and filter manufacturer to come to this conclusions.

Ken Brown   Owner at Eco Fluid Center Ltd.

Elena, this can be a problem with some Group II oils depending on the formulation. If you are following D4378 then you have RPVOT, Ruler or FTIR and Insolubles data. Can you share it? Unfortunately D4378 was issued in 2013 and in 2014 ASTM issued D7843 for the MPC (membrane patch colorimetry) test. This can be very helpful. As one option see http://www.fluitec.com/mpc-varnish-potential-testing.php

You need to involve your oil supplier to see if they have solutions. The first step is try to prevent it. If not then you have to install equipment and/or different filter elements to remove the varnish materials. Bleeding and feeding new oil regularly can also be an option but you have to sort out the costs.

Varnish deposits from steam turbine oils

Use of Group II oils is trending up, but formulating the correct additive package is essential

DURING THE LAST 10 YEARS, changes in steam turbine operating conditions and oil formulations have caused a variety of problems for steam turbine operators. Research by turbine manufacturers, power companies and oil suppliers has shown the main causes of the problems to be an increased use of API Group II base oils in turbine oils, combined with an increase in steam turbine peaking operation. The highest profile problems were entrained air and foam, decreased demulsibility and formation of varnish.

API classifies mineral base oils into three categories: Group I, Group II and Group III. The basis of the classification is the saturated hydrocarbon content, sulphur content and viscosity index of each type of base oil. Saturated hydrocarbons include paraffinic and naphthenic types; aromatic hydrocarbons are unsaturated.

The refining processes used to make Group I base oils mean they contain significant amounts of aromatic hydrocarbons (sometimes up to 20 percent by weight) and higher contents of naphthenic hydrocarbons. Measuring by weight, a typical 150 SN Group I base oil will contain around 50 percent paraffinic hydrocarbons, around 35 percent naphthenic hydrocarbons and around 15 percent aromatic hydrocarbons.

Conversely, the refining processes used to manufacture Group II base oils chemically convert many of the aromatic and naphthenic hydrocarbons into paraffinic hydrocarbons. As a result, a typical 150 N Group II base oil has about 68 percent of its weight in paraffinic hydrocarbons, around 30 percent naphthenic hydrocarbons and only around 2 percent aromatic hydrocarbons. Some Group II base oils contain almost no aromatic hydrocarbons. Naphthenic and aromatic hydrocarbons exhibit higher solvency properties than paraffinic hydrocarbons but are poorer on oxidation stability properties.

As a consequence of better response to oxidation inhibitors, oils formulated with Group II base oils have been found to give better results in some oxidation tests compared to oils formulated with Group I base oils. This has resulted in the increasing use of Group II base oils in industrial lubricants that are subject to oxidation such as steam turbine oils.

When mineral oils are exposed to high temperatures in the presence of air (oxygen) and entrained water, they oxidize. Oxidation products include acids, esters, alcohols, ketones and polymeric compounds, all of which are attracted to each other and to metal surfaces. When present in sufficient amounts, they can precipitate out of solution, forming varnish and eventually sludge.

Unfortunately, because Group II base oils have poorer solvency properties compared with Group I base oils, when they do oxidize they tend to produce varnish and sludge more quickly. Also, when some aminic oxidation inhibitors degrade, they can form varnish on metal surfaces.

The greatest problem with varnish in a steam turbine lubrication and control system is that it plates out on servo-valve surfaces, leading to valve sticking, and plugs the last-chance filters (LCFs) that are part of the servo-valve assembly. LCFs made with sintered metal or fine screens provide a convenient surface for varnish formation because of their location in the low-flow, colder hydraulic control section. Lower temperature promotes varnish formation because of the lower solubility at lower temperatures, which causes it to come out of solution and deposit on the filter's metal surface.

In addition, varnish precursors form deposits on mechanical seals, Babbitt sleeve bearings, thrust-bearing pads and orifices, resulting in restrictions. When these deposits develop on heat exchanger and reservoir walls, reduced heat transfer and higher temperatures are likely to occur.

Varnish can be removed from steam turbine oils using either electrostatic or adsorptive filters, but it's preferable to prevent varnish formation on metal surfaces in the first place. If formulators of steam turbine oils decide to replace a Group I base oil with a Group II base oil (to get better oxidation stability and longer oil life), the use of the correct types of oxidation inhibitors and the addition of small amounts of a polar base oil, such as an ester or alkylated naphthalene, is advisable. The polar base oil will improve the solvency properties of the Group II base oils, helping to keep any varnish precursors dissolved in the turbine oil.

Varnish can be removed from steam turbine oils, but it's best to prevent varnish formation on metal surfaces in the first place.

David Whitby is chief executive of Pathmaster Marketing Ltd. in Surrey, England. You can contact him at pathmaster.marketing@yahoo.co.uk

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Jean-Michel Demaret Technical Expert , Concentrating Mill Maintenance at PT Freeport

The ASTM standard for In Service monitoring of mineral steam and gas lubricant is ASTM D 4378. The standard stipulates **1000 ppm of water is a maximum**.

OEMs recommend the following values:
Alstom gas and steam 500 ppm, GE steam : 1000 ppm, Solar: 2000 ppm, Siemens/Westinghouse 200ppm.
The issue is water can either be absorbed in the oil or free (droplets). The free water is the issue. When the oil cool down (during shut down) more water becomes free. All your oil may not come back to your tank. The water present in the oil in contact with the critical components (bearings, valves) may initiate corrosion. Safe value is more around 100 ppm.

General information mentions that most turbine oils are saturated by 100 ppm of water at 40 C. At 20 C you will get some free water but not a lot. With 2000 ppm of water more likely you get 1900 ppm of free water during shut down.. The other issue with high water is that if your anti-wear / antioxidant package is made of ZDTP, the metallo organic compound will react with water and either drop or clogyour filter within 2 or 3 years of your oil in operation.

Dolf van Asbeck Technical Support Engineer at Shell Global Marine Products Ltd

Notice the range of values suggested by the OEMs. In steam turbine systems the water-trap maintenance is absolutely vital. It is the simplest way and will achieve results within the OEMs' published limits. Focus on the water traps and combine on-site lubricant testing for water that your team can do as often as is required to gain control of the system, with your normal used oil analysis programme. By the way, good water-trap management also reduces energy losses.

James Coxhead Owner at TERMOLUB EIRL

For proactive maintenance, I use top limits of 200 ppm (0.2%) for steam and 500 ppm (0.5%) for gas turbines, considering these limits for free water, the worst condition.

Peter Weismann Technical Director bei OelCheck GmbH

It is binding for all turbines or turbo compressors operating in Europe that the water content should not exceed 150 ppm (0,015%)
The DIN 51515-1 Standard for turbine oils specifies the water content for fresh and used turbine oils as max 150 ppm (0,015%). Such a low water content can only be measured according to a precise K.F. method.
The chair of the DIN working group was Dr. Quick from Siemens, all of the european turbine manufacturers like MAN, MTU, Alstrom, RollsRoyce, Mitsubishi and all major turnine oil manufacturers like ExxonMobil, Shell, BP as well as end users like Vattenfall, RWE, e-on, insurance companies like TÜV and OelChech an independent laboratory have established this Standard not only for water but also for all other important parameters.
There is also a publication available from this working group summarising all parameters and their interpretation especially for used turbine oils at the VGB: http://www.vgb.org/shop/s-416e-ebook.html

Alessandro Paccagnini, CLS / MLT-I In-Service Oil Analysis Laboratory Manager, Head of Diagnostics presso Mecoil Diagnosi Meccaniche Srl, Firenze

Jean-Michel, **version 2013 of the ASTM D4378 specifies a limit of 200 ppm** for turbine oil, both steam and combined cycle, this is much more aligned with OEMs requirements than the previous limit. This is about total water, be it dissolved, emulsified or free; water in this concentration range can only be accurately determined by Coulometric Karl Fischer titration.
The biggest issue here is sampling, because turbine oil can have a very high ability to separate from water (demulsibility). Especially for steam turbines, it is important that samples are taken from oil lines and NOT from the tank. Water concentration can vary very much with tank sampling height.

Mile Stojilkovic Director at NIS Gazpromneft, Department Lubricants – NISOTEC

Allowed water content in turbine oil is defined by the standards that must satisfy:

DIN 51515-1 (L-TD) and DIN 51515-2 (L-TG) = max.150 ppm (method ISO 12937)

GEK 107395a (VG 32) = max.0,02%; GEK 46357E/99 (VG 46) = max.0,01%;
GEK 46506D (VG 32) = max.0,01% (method ISO 12937)

SIEMENS TLV 9013 04:99 (VG 32; VG 46) <100ppm (method ASTM D1744/D1533)

John Bullous Business Development at Colfax Fluid Handling

I basically agree with Damanik and James Coxhead on water content issue: The most commonly used Standards that lay out water content for turbines are the ASTM 6224 and the ISO 8068. However, in any system water should be limited as much as possible and although 200-500 ppm could be acceptable depending on if steam or gas turbine, remember that these are the Maximum not the desired levels. In rolling element bearings for example the amount of water allowed according ISO 281 bearing design life calcs to achieve L10 life is 100 ppm and although this is for EHD not HD contacts, I would always recommend using this as a guide in any application due to the resulting benefits. If your with Methanex I would assume you are using gas turbines so please watch water carefully or you could end up with other issues including varnish build up by not monitoring this item carefully.

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SVR

Lubricant varnish production is a problem that will affect most rotating equipment at some point in their normal service life-time. While Varnish is not a complex issue that is difficult to solve, most users lack the basic tools required to test and maintain their lubricants. As a result, equipment owners experience billions of dollars in avoidable losses each year as a result of lost production from lubricant varnish. With tight capital budgeting process, many equipment operators react to lubricant varnish as failure is near rather than proactively manage to completely avoid this common failure pathway.

A Lubricant begins to break-down from oxidation from the first day it goes into service. The oxidation process creates dissolved oil break-down products that accumulate in the lubricant. Lubricant varnish is created once the oil reaches it saturation point for these oil break-down products, with the excess spilling out of solution and into varnish. Varnish is attracted to metal surfaces so by the time varnish forms, the risk to mechanical components is already present. A number of particulate removal devices are commonly sold to manage lubricant varnish levels. Unfortunately, these particulate removal devices cannot remove the varnish precursors which are dissolved in the lubricant so they have to wait for varnish to form before they can offer benefit. As discussed above, by the time varnish forms the risk profile to the equipment is already present, so using such devices offer limited benefit from a risk management perspective.

EPT offers a comprehensive program that will not only remove varnish, but will also remove the precursors, preventing their accumulation, thereby eliminating the potential for varnish formation. Our program is offered as part of a straightforward 4 step process as outlined below:

1. In our initial **lubricant assessment** we perform extensive testing to learn as much as possible about your lubricant's starting condition and to demonstrate the impact of our cleaning process.

2. Soluble Varnish Removal (**SVR™**) restores the lubricants natural solvency characteristics quickly stopping most cases of servo valve sticking. Solid varnish is dissolved back into the lubricant and removed. More importantly, varnish precursors are also removed, disrupting the varnish formation cycle as long as **SVR™** is used.

http://www.cleanoil.com/images/stories/pdfs/EPT-SVR1200SpecSheet.pdf

3. Filter sparking is a little known problem within high-pressure filtration systems. Normally, the evidence relating to filter sparking is confused with micro-dieseling or dirt ingression. The consequences of filter sparking are similar to these issues, but there often tends to be a noticeable "clicking" or "tapping" sound emanating from the filter vessels and visible burn-marks on filter parts.

The electrical discharge, or sparking, is caused by a similar process as walking across a carpet and touching a metal surface. The high flow rate of fluid through the majority of the mechanical filters on the market causes friction, which, in turn, builds the electrical charge one the filter. Eventually, the charge becomes so large that a spark occurs from the filter to the grounded filter housing. The problem is all lubricants are affected by the temperatures reached beside these localized sparks.

The sparks can have temperatures upwards of 10,000 degrees Celsius. At these temperatures, lubricants instantly breakdown and produce detrimental by-products.

EPT/Hy-Pro No-Spark Discharge (NSD) filters provide the same filtration efficiency as standard filters, but supress all possibility of filter sparking. Many other no-spark filter elements reduce sparking by increasing the micron rating of the filter (strainer), but the NSD design allows down to a 3 micron absolute rating. See specification sheet for more information.

Eliminating high temperature breakdown does not eliminate varnish formation, but does protect lubricants and important antioxidant additives from this common destructive mechanism.

4. All customers of this program receive documented oil analysis results until success is achieved. Our SVR system is guaranteed to deliver results when used as part of this program. After normal MPC results are achieved (≤15ΔE), the lubricant testing and monitoring program can be continued for a fee to insure varnish does not return.

http://www.cleanoil.com/service/varnish-mitigation.html
in
http://www.cleanoil.com/contact/distributors.html – none in RSA

VARNISH CONTAMINATION HAS POLAR PROPERTIES?

Ghasem Shilati Technical Manager at Naham Pala Engineering CO. Top Contributor

Varnish contamination is a common problem in many gas turbine oils.
Numerous papers are available discussing about varnish contamination, causes and remedies.
In most papers "polar properties" of varnish content has been accepted as a proven fact but our researches and experiments does not show polar property for varnish content.
Knowing real properties could help us improving new technologies for varnish removal.

Robert Bowden, CLS RWB Consulting LLC, CEO

Without the polarity of varnish molecules, electrostatic filters would not work.....however, they are very effective at varnish removal. I and many others have plenty of case studies and pictures to prove it.

Ghasem Shilati Technical Manager at Naham Pala Engineering CO
Electrostatic separators are based on **dielectrophoresis theory**. So **they CAN separate both polar or non-polar objects** at the same time. Of course electrostatic separators are not able separating varnish in soluble phase. Here is our experiment details which reject polar properties for varnish content:

1) MPC of sample oil found 85 which shows very high varnish contamination.
2) Dielectric constant was measured.
3) Oil sample was purified and after varnish removal MPC found was about 12 which shows very low contamination.
4) Dielectric constant of purified oil was measured. Done at the same normal conditions.
5) No changes observed between oil dielectric constant before and after vanish removal.

It means varnish content does not have polar properties otherwise oil dielectric constant should REDUCE after varnish removal.

Robert Bowden, CLS RWB Consulting LLC, CEO

I don't necessarily agree with your conclusion. Dielectric Strength is a good test for some situations, but there are several things that can influence it which could lead to a false positive. The MPC test itself (filtration and colour measurement) is also a source for variation that could seriously impact the results.

I don't want to cause an argument, but I spent 40+ years in an oil R&D lab and have run that test many times.

Ghasem Shilati   Technical Manager at Naham Pala Engineering CO.

1) I agree with you that MPC test is not so accurate but at least give us an estimation about varnish content. (MPC 85 is much bigger than MPC 12)

2) Separation of varnish has been done by our technology (ESVR) .This is Electrostatic Soluble Varnish Removal Package which has been improved by our company to remove soluble varnish at turbine oil running temperature.

3) "Dielectric strength" is not my point. We are measuring "dielectric constant" which is a test for quantifying degree of polarity for liquids.

Water as a polar liquid will influence "dielectric constant" even with a few PPM mixed with oil. It means if any polar substance (like varnish) is solved in oil, it should increase dielectric constant, but we did not observe any real rise.
If varnish is a polar substance it should increase "dielectric constant" when dissolved in oil.

Jean-Michel Demaret   Technical Expert , Concentrating Mill Maintenance at PT Freeport

If we look at the different phase of varnish creation we may find the answer to your question regarding its supposed polarity. Without getting in the details we have **a series of chemical reaction during the oxidation** of the hydrocarbon. We obtain active alkyl peroxy radical (polar) and active alkyl hydroperoxy radical (polar). These 2 alkyl attract hydrogen atoms from hydrocarbon molecules. These oxidised hydrocarbon molecules became polar and eventually polymerise with each other creating a longer chain even more polar (both have negative charge) ultimately being the varnish precursor. In the same time organic formic acid is created. I vote for polar.
PS: your experiment is interesting but I would oxidise transformer oil and see if there is a change in the dielectric strength.

Lourens Rhijnsburger   Inside sales RMF Systems at Doedijns Hydraulics bv

- Dear Ghasem,
  > I believe Oil Contamination Monitoring Technology Based on Dielectric Constant is in progress and finds good opportunities in future market.
  It would be interesting to compare our very sensitive sensor we use for monitoring Oil degradation if this can be used for your purpose.
  http://www.rmffilter.com/products/condition-monitoring/oil-quality-sensor/
  That varnish contains polar compounds does not automatically mean that all the turbine oil has polar properties.
  Please take care of difference between "dielectric strength" and "dielectric constant". Obviously oil oxidation products decreases "dielectric strength" - as you mentioned - due to reduction in oil resistivity properties. But "dielectric constant" is something different which shows polar properties of substances. "Dielectric Constant" is not a routine test to be done in common oil laboratories.

Jean-Michel Demaret
Dielectric constant: Basically the lab runs a current between 2 plates separated by the oil and record the equivalent capacity value. Then it is compared to the capacity value if the equipment was in vacuum.
The issue in doing this this test with turbine oil is that most of the additives are polar. What is the ratio between the polar charge of the additives compared to the polar charge of the varnish (if polar) I do not know. Additives polarity may be a lot higher and masks the removal of the varnish polarity. By using an oil with no additives (non inhibited transformer oil) you will get a better idea if the by

product of oxidation is polar. It may not be that simple because you need to extract the varnish out of the other by products (acid) and then dilute it in a solvent.

Ghasem Shilati Technical Manager at Naham Pala Engineering CO
I am not chemist but as a rule polar substances have a very very poor solubility in non-polar liquids like turbine mineral base oils.
For example water as a polar liquid is solving in mineral oil maximum up to 300 ppm at ambient temperature. It means capacity of base turbine oil for solving polar additives is drastically low. So I guess most of turbine oil additives should be non-polar in order to stay in solution without undesired settling or separation.

Practically adding very low ppm of water to mineral oil (even less than 10 ppm) increases dielectric constant of mixture. Based on this rule some water in oil sensors are available in market which measures water contamination by measuring oil dielectric constant. These types of sensors have an accuracy about 5 ppm or even less.

I believe quantity of polar additives in mineral oil should be non or much lower than influencing or masking varnish presence.

Elena Yolova Lubricants Expert at "SGS Bulgaria"Ltd

Varnish is a mixture of a lot of different substances. Oxidation products (which form varnish in the lubricant) may be polar and non-polar. When we want to analyse them we dissolved or precipitate it in polar or non-polar solvents. For example ASTM D 893.

In other hand we can measure additive content in turbine oil by linear sweep voltammetry ASTM D 6810 and ASTM D 6971.

In third, in used oil there are a wear metals and metal particles which can collect in varnish as in web.

Alessandro Paccagnini, CLS / MLT-I In-Service Oil Analysis Laboratory Manager, Head of Diagnostics presso Mecoil Diagnosi Meccaniche Srl, Firenze

Ghasem, I see that you are using a fairly sensitive sensor for measuring dielectric constant, able to resolve tens of ppm of water. This does not automatically mean that it will work equally well for detecting varnish precursors, so in my opinion you are not seeing any change in dielectric constant because of the masking effect of other polar compounds in the oil (e.g. additives as stated by J-M) and because you detection system is probably not enough sensitive.
One cannot compare the polarity of varnish precursors with the polarity of water: there are several orders of magnitude of polarity and complexity between the two. Some varnish precursors chemical species (which are extremely heterogeneous) have small polar groups within large nonpolar regions in the molecule structure: this is also true for additives.
So far, I think that your experiment is a good representation of what's going on in many turbine lubricants, but in my opinion your conclusion that varnish precursors are entirely nonpolar is wrong.

Beatriz Graça Engineer at INEGI

My experience on that shows me that it results from degradation products of the lubricant - soft contaminants (additives and other chemical compounds). Through Ferrography the varnish process generation was well . See paper: http://www.machinerylubrication.com/Read/28580/lubricant-analysis-in-steam-turbines-
This process is not exclusive of turbine oils, I already detected the same kind of particles in hydraulic oils, gear oils, etc. But all the soft particles resulted from degradation products are polar and magnetic.

Ghasem Shilati

Usually we are doing MPC test for our customers before and after varnish removal from turbine oil for initial approval. As you know, Membrane Patch Colorimetry needs a diluted oil in order to be passed through 0.45 mic membrane. Usually we are using Petroleum Ether for diluting oil sample. We found for some cases that the volume of Ether we are using for diluting AFFECTS the final test results! But for most cases volume of Ether has no effect on MPC test results.

Petroleum Ether as a non-polar liquid used for diluting non-polar base oil but sometimes it also dissolves degradation products which seems to be polar and insoluble!
My final conclusion: VARNISH is a complicated soft contaminant with polar or non-polar properties. So VARNISH can be exist in both polar / non-polar nature.

Robert Bowden, CLS
I think, what we are calling "varnish" CAN be a complicated mixture of oxidized base oil molecules (polar), dirt (polar and non-polar), wear metals (mostly polar), additives (polar and non-polar), moisture (polar) and don't forget those aftermarket magic additives (polar / non-polar???). So yes, I agree with your final conclusion.

Fortunately for me, this conclusion also aligns with what I have learned over the past many years when trying to remove "varnish" from turbine oils and why measuring "success" sometimes is subjective and can have huge variation.

Ghasem Shilati

Apart from our discussion, it seems MPC test procedure (ASTM D7843) needs immediate modifications in order to void final results variations by different types of turbine oil samples.
I can send them an oil sample with variable MPC test results corresponded to volume of solvent used!

Mark Latunski   Lab Manager at American Chemical Technologies, Inc.

The best model for predicting the chemical behaviour of pre-varnish is to view it as an inverse micelle. There is a polar core that concentrates aromaticity, hetero-atoms, and water. We have determined that antioxidants, corrosion inhibitors, and oxidation by-products can all be found within this microstructure. The model predicts that the aliphatic hydrocarbon side-chains extend away from the central core. It is perfectly reasonable that magnetic contaminants could also be found in this micelle.

Reasonably, anything more polar than an aliphatic hydrocarbon will eventually find itself at the core of these soft-contaminants.

It is with this model that we have been able to predict conditions that are catastrophic to the operation of a turbine. However what is more important to the turbine operator, it is with this model that we have been able to successfully eliminate all issues associated with varnish formation in turbine oils without increased reliance upon exotic forms of filtration.

Elena Yolova

As we discuss this topic- in recent times my clients have a problem with the solubility of oxidized products in turbines and hydraulic oils - at operating temperatures (60-80 C) are dissolved, but in stoppage (i.e. temperature below 25 C) become insoluble and begin to deposit on working surfaces. It is a great problem with the hydraulic piston pumps.

Jean-Michel Demaret

@ Elena Your problem is quite interesting, and I would not mind commenting on it. Could you open a discussion. Ghasem discussion is quite specific and it may lose some interest if we branch out.

@ Mark What you explain to us is that as an inverse micelle has the polar head in the middle of the sphere and tail toward the outside. It attracts any polar particles including anti-wear, corrosion inhibitor and detergent/dispersant (if any), water and more polar varnish precursor and may be organic acid, ketone...until it becomes big enough to drop or be removed by a filter. It is important to estimate the critical mass/ molar mass of the micelle at which it will become a problem.

Mark Latunski   Lab Manager at American Chemical Technologies, Inc.

When you prevent the varnish micelle from forming and dissolve the varnish that already exists in your system, cold temperature cycling issues become a thing of the past. When you can accomplish this in a hydrocarbon lubricant down to temperatures of -40 C, you have a game-changer.

It is patented technology. So Robert is correct, it is a discovery that is currently being implemented on a world-wide scale.

Perry Thiessen   C.C.JENSEN Oil Filtration

Here is an article which covers varnish removal by adsorption:
http://www.cjc.dk/fileadmin/user_upload/pdf_usa/Removing_Varnish_with_Adsorption.pdf

Ghasem Shilati

The referred paper has some good points and facts, but obviously using science for its own sales pitch.
Adsorption filters are efficient only for insoluble suspended degradation products removal. Van der Waals and electrostatic forces are so poor and have no ability overcoming strong soluble varnish molecular bonding.
After all these forces are not so smart to remove varnish molecules selectively without affecting existing soluble additives!

Ghasem Shilati

I believe Oil Contamination Monitoring Technology Based on Dielectric Constant is in progress and finds good opportunities in future market.
This inexpensive test can lightening existence or increasing rate of contaminants in oil which most of them are polar and affecting oil dielectric constant.(like water ,degradation products and metallic ions).
Here is our simple method for measuring oil dielectric constant.

1)Two sheets of 1 mm stainless steel by dimensions of 10x20 cm.
2) Fix these two sheets by distance of 3 mm between them, bolt together by a 3 mm isolated spacer between them. Then glaze two pieces of wire connected to each ones.
3) Now insert made sensor inside a plastic bowl vertically and fill the bowl by the sample oil you are going to measure dielectric constant.
4) This is like a flat capacitor and oil roles as dielectric when filling the space between sheets.
5) Measure capacitance by a capacitance meter available in market. (Just connect two wires to measure capacitance in pf.)
6) You can calculate oil dielectric constant by this formula

C =E0. K.A /D >>>>> K = C.D/ (E0 . A)
E0= 8.85X10^ -12
C = Measured by capacitance meter
A = 0.02 M2
D = 0.003 M

K= DIELECTRIC CONSTANT

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Varnish deposits from steam turbine oils

Use of Group II oils is trending up, but formulating the correct additive package is essential

DURING THE LAST 10 YEARS, changes in steam turbine operating conditions and oil formulations have caused a variety of problems for steam turbine operators. Research by turbine manufacturers, power companies and oil suppliers has shown the main causes of the problems to be an increased use of API Group II base oils in turbine oils, combined with an increase in steam turbine peaking operation. The highest profile problems were entrained air and foam, decreased demulsibility and formation of varnish.

API classifies mineral base oils into three categories: Group I, Group II and Group III. The basis of the classification is the saturated hydrocarbon content, sulphur content and viscosity index of each type of base oil. Saturated hydrocarbons include paraffinic and naphthenic types; aromatic hydrocarbons are unsaturated.

The refining processes used to make Group I base oils mean they contain significant amounts of aromatic hydrocarbons (sometimes up to 20 percent by weight) and higher contents of naphthenic hydrocarbons. Measuring by weight, a typical 150 SN Group I base oil will contain around 50 percent paraffinic hydrocarbons, around 35 percent naphthenic hydrocarbons and around 15 percent aromatic hydrocarbons.

Conversely, the refining processes used to manufacture Group II base oils chemically convert many of the aromatic and naphthenic hydrocarbons into paraffinic hydrocarbons. As a result, a typical 150 N Group II base oil has about 68 percent of its weight in paraffinic hydrocarbons, around 30 percent naphthenic hydrocarbons and only around 2 percent aromatic hydrocarbons. Some Group II base oils contain almost no aromatic hydrocarbons. Naphthenic and aromatic hydrocarbons exhibit higher solvency properties than paraffinic hydrocarbons but are poorer on oxidation stability properties.

As a consequence of better response to oxidation inhibitors, oils formulated with Group II base oils have been found to give better results in some oxidation tests compared to oils formulated with Group I base oils. This has resulted in the increasing use of Group II base oils in industrial lubricants that are subject to oxidation such as steam turbine oils.

When mineral oils are exposed to high temperatures in the presence of air (oxygen) and entrained water, they oxidize. Oxidation products include acids, esters, alcohols, ketones and polymeric compounds, all of which are attracted to each other and to metal surfaces. When present in sufficient amounts, they can precipitate out of solution, forming varnish and eventually sludge.

Unfortunately, because Group II base oils have poorer solvency properties compared with Group I base oils, when they do oxidize they tend to produce varnish and sludge more quickly. Also, when some aminic oxidation inhibitors degrade, they can form varnish on metal surfaces.

The greatest problem with varnish in a steam turbine lubrication and control system is that it plates out on servo-valve surfaces, leading to valve sticking, and plugs the last-chance filters (LCFs) that are part of the servo-valve assembly. LCFs made with sintered metal or fine screens provide a convenient surface for varnish formation because of their location in the low-flow, colder hydraulic control section. Lower temperature promotes varnish formation because of the lower solubility at lower temperatures, which causes it to come out of solution and deposit on the filter's metal surface.

In addition, varnish precursors form deposits on mechanical seals, Babbitt sleeve bearings, thrust-bearing pads and orifices, resulting in restrictions. When these deposits develop on heat exchanger and reservoir walls, reduced heat transfer and higher temperatures are likely to occur.

Varnish can be removed from steam turbine oils using either electrostatic or adsorptive filters, but it's preferable to prevent varnish formation on metal surfaces in the first place. If formulators of steam turbine oils decide to replace a Group I base oil with a Group II base oil (to get better oxidation stability and longer oil life), the use of the correct types of oxidation inhibitors and the addition of small amounts of a polar base oil, such as an ester or alkylated naphthalene, is advisable. The polar base oil will improve the solvency properties of the Group II base oils, helping to keep any varnish precursors dissolved in the turbine oil.

Varnish can be removed from steam turbine oils, but it's best to prevent varnish formation on metal surfaces in the first place.

David Whitby is chief executive of Pathmaster Marketing Ltd. in Surrey, England. You can contact him at pathmaster.marketing@yahoo.co.uk

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A rather large number of factors influences lubricating oil degradation and, consequently, pump bearing life. If your centrifugal pumps are equipped with rolling element bearings,

there is little doubt that medium viscosity turbine oils (ISO Grade 68) will perform better than the lighter oils originally specified by many pump manufacturers. But, by far, the most frequent cause of lube-oil-related failure incidents is water and dirt contamination. With only 20 ppm water in pure mineral oil, bearing surface and rolling element fatigue life is reduced by an incredible 48 percent. Although the fatigue life reduction is less pronounced with inhibited lubricants, there are always compelling reasons to exclude dirt and water from pump bearing housings. Lip seals are a poor choice for centrifugal pump installations demanding high reliability. Face seals represent superior, "hermetic" sealing and should be given serious consideration.
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"On a related subject, have you explained to your operators and maintenance personnel that a full-bottle oiler is no guarantee of adequate lubrication? The height of the beveled tube determines the level of oil in the bearing housing, and all too often there will be costly misunderstandings. However, there are at least two considerably more elusive problems involving bottle oilers.

"The first of these is that bottle oilers may malfunction unless suitably large bearing housing vents are provided. With a relatively viscous oil and close clearance at the bearing housing seal, an oil film may exist between seal bore and shaft surface. Good lube oils have a certain film strength and under certain operating conditions, this sealing film near the bearing end cap may break only if the pressure difference bearing housing interior-to-surrounding atmosphere exceeds 3/8 inch of water column.

"If now, the bearing housing is exposed to a temperature increase of a few degrees, the trapped vapors - usually an air-oil mix - floating above the liquid oil level will expand and the pressure may rise 1/4 inch of water column. While this would not be sufficient to rupture the oil film so as to establish equilibrium between atmosphere and bearing housing interior, the pressure buildup is nevertheless sufficient to depress the oil level from its former location near the center of a bearing ball at the 6 o'clock position to a new level now barely touching the extreme bottom of the lowermost bearing rolling element. At that time, the bearing will overheat and the lube oil in contact with it will carbonize. An oil analysis will usually determine that the resulting blackening of the oil is due to this high temperature degradation.

"The second of the elusive oil-related problems often causes the contents of bottle oilers to turn grayish color. This one is primarily observed on ring-oil lubricated rolling element bearings.

"Suppose you have very precisely aligned the shafts of pump and driver; nevertheless, shims placed under the equipment feet in order to achieve this precise alignment caused the shaft system to slant 0.005" or 0.010" per foot of shaft length. As a consequence, the brass or bronze oil slinger ring will now exhibit a strong tendency to run "downhill." Thus bumping into other pump components thousands of times per day, the slinger ring gradually degrades and sheds numerous tiny specks of the alloy material. The specks of metal cause progressive oil deterioration and, ultimately, bearing distress.

"Pump users may wish to pursue one of two time-tested preventive measures. First, use properly vented bearing housings or, better yet, hermetically sealed bearing housings without oiler bottles. The latter are offered by some pump manufacturers and incorporate bull's-eye-type sight glasses to ascertain proper oil levels.

"The second preventive measure would take into account the need for radically improved pump and driver leveling during shaft alignment or, even more desirable, apply flinger spools. Of course, oil mist lubrication or direct oil injection into the bearings would represent an altogether more dependable, long- term satisfactory lube application method for centrifugal pumps."

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Q: Do turbine oils contain succinic acid ? In additives - as understood from certain OEMs that it reacts in compressors in fertilizer plant having ammonia service.

A: Some additive chemistries have used dibasic carboxylic acid and alkyl or alkenyl succinic acid.

Succinic anhydride derivatives are very common dispersants, usually as succinamides. So if there is some of this type of dispersant additive in a turbine oil, then there could be some chemical interaction with another amine, like ammonia. Amides are pretty stable though, which is why they are so widely used, but lots of things can happen at high temperatures.

Alkyl Succinic acid anti rust additives are widely used in turbine oil formulations where they perform extremely well "in turbine applications". However, for ammonia compressors (turbo compressors) it is essential to use another type of anti-rust/corrosion component in the lubricant, maybe a sulphonate type which would not react negatively with ammonia.

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All oils are prone to oil degradation, which can lead to the production of varnish. Varnish production is as a result the breakdown of the oil, either due to operational effects, such as shear stress and temperature and from contamination in the oil, such as wear metals, water and oxidation. This degradation process is what causes sludge to form and results in varnish deposits.
Varnish deposits on a journal bearing can cause dirt and particulate to stick to it, giving rise to excessive wear or loss of lubricity. Oil degradation can also result in increased viscosity and higher levels of acidity in the oil.
You cannot stop oil degradation happening, but you can take steps to reduce the effect of varnish and the production of varnish by removing the wear particles, water and reducing acidity build up.
http://www.cjc.dk/contamination/oil-degradation/
Frequent topping up of the oil will not cause varnish production, in fact it will act as a "cleaner" to dissolve some of the varnish back in to the system. Using such a system indicated in the link will help remove the contaminants from the oil and will then allow the oil's natural detergency to help clean the system of varnish over time. A recent development in this technology has vastly improved the efficiency of varnish removal to reduce the time taken to clean a system.
Simple tests, such as colourimetric millipore membrane analysis or QSA looks at the colour of a membrane after drawing a sample of the oil through it. The level of staining from yellow to dark brown will give an indication of potential varnish. Monitoring the anti oxidant additives is also a way of checking on oil life using the RULER test or RBOT or RPVOT tests. Ultracentrifuge tests give a good indication and Infrared Spectroscopy are some others. You should not, however, forget to check oil viscosity and TAN levels as this is also a good indication of the condition of the oil. Increased viscosity, high acidity, dark brown oil colour and a sour smell of the oil all indicate a high level of oil degradation and the likelihood of potential varnish products in the oil.

The main problem with water in HFDU fluids is that it will cause acidity, which can have a serious affect on seals in the machinery. I have seen the results of a company using HFDU the same way as HFDA, mixing with water. Very expensive mistake!
There are ways to ensure moisture does not build up in the fluid, causing acidity and oil degradation, which leads to sludge and varnish production.

High temperatures can cause thermal degradation of the oil and combined with wear elements and water, which act as catalysts, can further degrade the oil. It will create acids and water. This will result in the production of a soft sludge which can stick to hot spots, or to cooler parts, such as filters, cooler plates/tubes and spool valves, where lacquering will occur, causing damage to fine tolerances, block filters and make coolers inefficient. Removal of varnish and acidity will help keep components cleaner and reduce the risk of outages caused by degraded oil.

The process you described is called "hydrolysis" and is the most common degradation manner of any synthetic ester fluid, HFDU included. Water is the primary cause of hydrolysis, but high temperatures can contribute to it.
I would also say that people commonly refer to Varnish as the degradation product formed by mineral paraffinic lubricants, where HFDU hydrolysis normally generates the soft sludge that Sandy wrote about. In my experience, HFDU degradation needs to be monitored using a different approach than mineral oil degradation. With HFDU fluids, the most important indicator of oil ageing is Acid Number, because it directly measures the concentration of the non-esterified (that is: hydrolized) fatty acids.
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Generally, the rate of lubricant degradation doubles with every 18 degrees F increase in temperature. Once formulated with antioxidant additives, PAO-based lubricants have a lower baseline rate of oxidative degradation. At low temperatures, a PAO's increased oxidative life may not be noticeable, particularly if you have to change the oil at some point for other reasons. At higher temperatures, the synthetic may last noticeably longer.

Typically, you begin to notice the extra life provided by a PAO above 160 degrees F (71 C). If it is above 180 degrees F, and especially 200 degrees F, the difference in oxidative life becomes quite apparent. However, the point at which a change to synthetic is justified is dependent perhaps on a handful of additional "program management" parameters such as:

1. Do you intend to run your gear oils with an appropriate use of filtration and oil analysis to support life-cycle extensions for many years?

2. Are you currently doing oil analysis and performing condition-based changes?

3. Do you have, and have you communicated to your lab, oxidation limits that flag impending oxidation problems?

4. Does the machine's operating temperature vary a great deal (a PAO's high viscosity index enables it to operate across a wider temperature range)?

5. Do you have an effective contamination control program in place that will enable you to fully exploit the PAO's extended life?

With the appropriate management strategy, a change to a high-performance product can actually cost considerably less than the equivalent mineral oil product type. Outside of these considerations, somewhere around 165 degrees F represents the point at which you probably should begin to consider the use of synthetics for the sake of lubricant longevity, if not for the sake of reliability.

http://www.machinerylubrication.com/Read/28606/hot-for-synthetic
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Mobil 932 Turbine Oil

Russell Flagg PdM/Reliability Specialist

Has ayone have any operating experience using the exxon Mobil 932 product in GE combustion turbines? If so I would appreciate what your findings are in regard to varnish prevention and servo valve performance.

Cristián Schmid

Businees Development

Russell. Our experience is that the best strategy for that is to perform a varnishing flushing in a outage or overhaul, and install a technology to prevent the varnishing formation like ISOPur. This technology is recommended by the GE TIL.

[Kevin Barnidge MLA II]

Safety and Operations Manager at Petrolink USA, LLC.
We just completed a flush at refinery that was using the 932 and had a varnish problem. Turns out they also had a water problem and high particle count. After the flush, they were at a 16/14/11 and maintain it by side stream filtration.
First, pull a sample and send it in to get an MPC test for the amount of insolubles in the oil and have PC and Karl Fischer ran as well.

[Mishel Sidorin]

Power Plant Manager

The real problem is the lack of engineering in the turbine oil system, the main oil filters, installed to protect the pump integrity normally have 25 microns, the filter in the servo control oil is 8 microns, but the internal moog filter have 0,5 microns. nothing clean the oil plus if you have a gear box, the problema is worse.
I recommend to use an external good capacity filters system with 1 micrón, keep your eyes on the oil cleanse and additives integrity and try to keep the oil hot to prevent varnish formation ,turn off the FFcoollers if your cycle your machines daily

[Kevin Barnidge MLA II]

Safety and Operations Manager at Petrolink USA, LLC.

Absolutely. We have installed 1 µm Beta 1000 filters at all the turbines and field fill lines at a plant in Mississippi. I like to say we work ourselves out of work there but that is always a great problem to have.

[Fernando Oscar Bilotti]

Senior Field Engineer Support - Argentina Area -Minería y Marine & Aviation Lubricants en Axion Energy S.R.L.
Very good comments. I agree with all of you: You need to check MPC and Ultracentrifuge UC test too, in order to check the pontential formation of varnish. I agree with the technology of ISOPUR or others. GE had tested some of them and contribute to reduce the varnish problems. I have only question. Do you refer to Mobil DTE 932 GT?
Take in consideration the following comment.
Particularly suited for General Electric frame 6, 7 and 9 applications where varnish control of the hydraulic system is desired.

[Raymond Gomes]

CEO at ISOPur Fluid Technologies, Inc

Actually, GE uses Isopur exclusively on its gas turbines, and now steam, as well. When used properly, they work. See the paper on our home page for the longest running test of an Isopur system on a GE frame 7. The oil is at 55,000 hours, 12 years on the original oil. They serviced servo-valves for the first time during the ten year tear-down.
http://www.isopur.com/Cases/55,000%20Varnish%20Free%20Hours%20Using%20BCA%20Oil%20Purification%20on%20GE%207FA%20Turbines.pdf

[G Shilati]

Technical Manager at Naham Pala Engineering CO.

What is making varnish contamination so difficult to handle is its degree of solubility which is directly depends on turbine oil temperature.

Varnish content is being solved at high temperature areas of turbine, then passing through even sub-micron filters and settles on colder sensitive parts like servo Moog valves.
I am sure there is no filter invented yet which capable of separating soluble varnish at turbine running temperature.

But we had good results in our company for separation of varnish contamination in gas turbines by on-line transferring it to dissolved phase and then separating by electrostatic technology.

Finally before wasting your money for solutions please be sure that your turbine oil remaining age and foaming factor are still in acceptable range. Otherwise renew the whole oil.

Raymond Gomes

CEO at ISOPur Fluid Technologies, Inc

You are right. **Power turbine manufacturers have chosen the single sump method for lube, hydraulic and seal oil. It is cheaper, so it gives them a price advantage.**

I attended a meeting at a major turbine supplier where I was talking about the single sump problem to the service and operations staff. One older engineers stood up and said, who would be so stupid as to use a single sump. One engineer at the back of the room pointed to himself and mouthed the words, we did.

As for temperature effects, this is the selling point for our competitor's solution. They needed something to set them apart from the electrostatic filtration systems that were working so well, so they came up with the temperature solubility issue. Of course, they were the only ones with a solution to this problem.

When you look at the results we got at TECO, you have to wonder, was it a miracle that seven Frame 7 turbines have run the same oil for 12 years and it is still cleaner than new? Maybe there is something wrong with this solubility issue. The turbines managed to remain varnish free in a semitropical area using our machines for over 55,000 run hours. They did not sent a single servo valve from 7 turbines out for repair until the 10 year tear-down. Could it be there is more to the temperature issue than the competitor claims? How have the 50 Isopur machines in Saudi manage to work so well? I believe much of this issue was contrived to sell machines.

Look at the original video that several companies use that shows "varnish" going into solution as the temperature of the oil is raised. You will note that at one point, the "varnish" is white. I believe it is the additive PANA that was used by several large oil suppliers 10 years ago. This additive is a waxy substance that melts around 45 C. I once had a chance to experiment with it and got the same results as our competitor. It fell out of solution as it cooled and became a solid and went back into solution when heated as it melted.

This solubility - temperature issue has been repeated so often, that it is now believed to be true by everyone. I believe there is more to the story. Either we create miracles with our machines, or the solubility-temperature issue is wrong. I don't believe in miracles!

Edmund T Bird

Advanced Fluid Systems, Inc. MA, RI, NH, ME & VT Sales Engineer

Varnish is formed by thermal events, heating and cooling. If your system shares sumps, it means critical servos are at risk. But even in systems where sumps are separate, I have seen varnish become an issue. The Iso-pure system is an electrostatic system, and is good up to a point. We sell the Hy-Pro SVR, it addresses both soluble and free varnish. It utilizes both mechanical filtration for free varnish, and dry Ion charge bonded elements to remove varnish in solution. It draws the varnish from surfaces in the system that can be left behind and become problematic using other methods. There are over 200 of these units being successfully used on turbines today.

Perry Thiessen C.C.JENSEN Offline Oil Filtration Systems (Canadian distributor)

We continue seeing good results with the C.C.JENSEN Varnish Removal Unit (VRU). We recommend 24/7 dedicated kidney loop filtration for turbine oil, rather than one time servicing.

The VRU keeps both particle counts and varnish levels very low by operating on a continual basis. We consistently see good data return from the field on Alstom, Siemens, and GE turbines. http://www.cjc.dk/products/varnish-removal-unit-vru/

Edmund T Bird Advanced Fluid Systems, Inc. MA, RI, NH, ME & VT Sales Engineer

https://www.hyprofiltration.com/case-studies/detail/general/svr-lube-oil-varnish-removal-success/?query=misc0.eq.1&back=CaseStudies

Brent Winter Industrial Field Marketing Advisor at ExxonMobil

Mobil DTE 932GT is a relatively new gas turbine oil when you think about turbine life cycle and the market standard of products. The Mobil DTE 932GT is designed to address the common problem in Gas turbines, minimize varnish. This product is currently in 30 turbines in the US and one has just eclipsed 30,000 hours.

A Solution to a Paradox in Turbine Bearing Temperatures

High-speed, low-load applications can result in higher-than-expected operating temperatures in directed lubrication bearings.

A testing program was conducted in order to determine the cause of the higher than normal temperatures and reduction of oil flow rate on leading edge groove (LEG) thrust bearings operating at high speed and light loads. Using the bearing manufacturer's test rig, the problem was duplicated and the reason for the behavior was discovered. Modifications to the bearings led to a solution that successfully eliminates the undesirable effects of this newly documented phenomenon. The following conclusions have been formulated through the testing program:

- The effect of this phenomenon yields higher than expected pad temperatures at light loads. As the load increases, the pad temperatures return to expected values. Additionally, with LEG type bearings, the oil pressure required to supply the recommended flow rate becomes very high.
- The phenomenon is observed in all types of hydrodynamic tilting-pad thrust bearings including flooded, directed lube, center-and offset-pivot, steel, and chrome copper backed bearings.
- The phenomenon occurs at mean sliding velocities above 300 fps and at light thrust loads. The actual load at which it occurs depends on the speed, but typically is in the range of zero to 100 psi unit load.
- The phenomenon is believed to occur when the moment due to viscous drag on the shoe surface exceeds the moment from the hydrodynamic oil film force. Viscous drag increases with speed and its moment can exceed the film force moment under light load conditions.
- A taper modification has proven to effectively address the phenomenon in directed lube and flooded designs by exerting additional hydrodynamic force at the leading edge. This additional force maintains the proper tilt of the shoe and keeps the leading edge gap open. Tests show that pad temperatures are reduced by as much as 80Â°F and oil supply pressures lowered by as much as 25 psi.
- The taper modification has been successfully applied at light loads in the OEM facility and at high loads in the field. The OEM reported that a handful of high speed

centrifugal compressors, incorporating the modification, is running well at full load and that "no problems have been reported regarding any of the respective thrust bearings."

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Viscosity Guide Table of Limits

Maximum Viscosities
Centistokes
(Normally At Start-Up)

22,000
Probably maximum pouring viscosity.
11,000
Probably maximum for splash or bath lubrication.
8,600
Barely pumpable by gear or piston pump too heavy to be serviceable.
2,200
Upper limit for an automatic oil lubricator.
2,200
Upper limit for circulation system (good practice).
2,200
Upper limit for an oil constituent of a grease for dispensing.
1,000
Ring or rolling element bearings.
860
Hydraulic Vane Pumps @ start-up temperature to prevent cavitation and wear.
860
Fuel oil for good pumpability and atomizing.
220
Oil mist generators without heat at minimum operating temperature.
220
Hydraulic-piston pump start-up temperature to prevent wear.
54
Hydraulic Systems at operating fluid temperature.

Minimum Viscosities
Centistokes
(At Operating Temperature)

33
For gear lubrication.
30
For a gear pump.
21
Spherical roller bearings.
13
Other rolling element bearings.
13
Hydraulic systems to prevent excessive pump wear and slippage.
13
Plain bearings.
4
Minimum viscosity to support a dynamic load.

Optimum Viscosities
The optimum viscosity is the ideal allowable at the operating temperature.-
Centistokes

25
Hydraulic systems

30
Plain Bearings
40
Spur & Helical Gears (e.g. ISO-VG 150 @ 60 °C)
75
Worm Gears (e.g. 460 @ 75 °C)

Product Feature

New Drum Pump Filtration System

Actively filtering lubricants from storage drums can prevent contamination related problems. Trico’s Drum Pump Filtration System can prevent contamination or remove it when used in daily operations, including filtering oil directly from the storage drum to fill totes and transfer containers. The Drum Pump Filtration System provides a dispensing nozzle capable of delivering a flow up to 6.8 gpm and is rated for use with lubricants up to a viscosity of 7,000 SUS, depending on motor selection. The Drum Pump Filtration System comes standard with a 10 micron absolute Beta>200 spin-on filter element and a sealing bung adapter. The universal design of the Drum Pump Filtration System integrates a quick change hand wheel design, allowing the motor to be transferred from one Drum Pump Filtration System to another without buying additional motors or removing the entire apparatus. This follows industries best handling practices by avoiding cross contamination of different lubricant types, reduces further particle contamination and eliminates messy lubricant spills. For more information visit our website:

http://www.tricocorp.com/products/product.aspx?c=28

Maintenance Tip

Oil Level Sight Glass

When inspecting oil level gauges, make sure the level seen through the sight glass is oil and not a permanent stain. There have been cases where equipment did not have proper oil levels because the stain on the sight glass appeared to be oil. If a stain is found, while the equipment is not in service, remove the glass and clean using an approved cleaner. If the stain cannot be removed, the sight glass should be replaced. Note: in emergency cases when another sight glass is not available, simply flip the glass and install the clean side down. It will allow you to inspect the lube oil level until another sight glass can be located and installed.