Predictive Maintenance
Versus.
Making Money

Or

Whatever happened to conventional maintenance?

By

Danny Bates
Southern Company Transmission

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Abstract

Budget cuts in both maintenance and capital projects while still maintaining reliability and meeting regulatory requirements has forced Alabama Power to think outside the box on how we spend our limited funds. Conventional time based maintenance has become a thing of the past much to the dismay of the "old guys" in the business. This paper will cover some of the ways Alabama Power is utilizing its resources including latest condition monitoring techniques.

Background

For time's sake we will only go back twenty years to 1989 and where Alabama was with it's maintenance practices and intervals related only to power transformers >115kV high side, generator step ups and their associated equipment. Then we will move forward to where we are and where we plan to go. The definition used for an "old guy" is anyone that involved in substation maintenance in the '70's. Those older than that should be retired by now and not be around to complain about all the latest regulatory and reliability requirements and say "what do you mean we're cutting back on maintenance, that's my job!"

Through normal retirement and early out packages Alabama Power has seen a lot of maintenance expertise leave before the new guy was ready to take over. Is this a bad thing? Maybe, maybe not. We cannot continue to look back at the old way we did our business but must look forward to how we can do our business better. SAIDI, SAIFI, NERC, FERC, SERC, PSC and ROE for investors are requiring us to reduce out cost yet maintain that 99.9% reliability our customers have become accustom to.

Today I'm considered an "old guy" and Carl Manger will back me up in saying that you reach a point in your career that you can say anything you want to about maintenance practices and could actually care less what everybody else thinks. I don't write formal technical papers or provide graphs to back what I say but, rather tell a good tale, so here's my story and it's up to you to believe it or not.

Where Were We

Time based maintenance intervals, and it seemed that most of the region supervisors were more comfortable performing maintenance on certain transformers than others. This philosophy led to a lot of time "putting out fires". We were focused on a few tests that seemed important to us and tended to ignore others. Incentive pay for the supervisors was tied directly to the number of pieces of equipment that was tested each year and the numbers were made public to each of the six maintenance areas. The average for each of the maintenance areas was 1,000 pieces per year including breakers and instrument transformers. But one must understand that a lightning arrester was considered a piece of equipment so a three phase auto w/tertiary accounted for ten pieces. Therefore they were eager to test an auto rather than a breaker which led to the selective equipment being tested.

What were those tests and activities?

- *Power factor*. Alabama Power had become a member of Doble users in 1934 and had gone from one guy testing what he felt necessary on no time based cycle to a three year cycle on select equipment. This required that manpower be added to the test group which had grown to five by 1980. The "equipment test guys" as they were called were an elite group and considered the transformer experts @ APCo. These guys performed a full battery of tests on all >115kV high side transmission and distribution transformers and those at generating plants when the plant would allow for an outage. Well, at least on paper the tests were performed.
- *Transformer turns ratio.* Royce Murray was the transformer shops superintendent @ APCo in the '50's through the mid '70's. Mr. Murray was considered somewhat of a genius and actually built the first TTR as we know it today used @ APCo (fig. 1). Until the early 80's this was one of test that could only be performed by the equipment test guys. Many a maintenance crew person asked what the test indicated and was told "none of your business, just hook it up like I tell you." As time went on a training program was developed for substation maintenance electricians that led to them actually enjoy performing ratio even if they didn't understand what the results were telling them. Later we acquired electronic ratio meters and the "old guys" questioned the accuracy of these gadgets. So, basically we were questioning that if an electronic device could be as accurate as the old hand crank no matter how fast you cranked it.

Fig. 1

- *Megger.* Now here's another favorite test that the maintenance electricians were allowed to perform that could tell if a transformer was good or bad regardless of the other test results (fig. 2). It was not uncommon to hear "well, it meggered good so I made it hot and it came right back out." "Then when I sniffed it with my McGraw combustible gas analyzer it went off scale, I don't know what happened!" "Did I ratio it?, that ain't my job." I'm not saying it's not a good test. The DC insulation test is still a valid test when performed right by our properly trained electricians. But, the question that comes to mind today is should we take an operating transformer out of service just to megger it without any other indication of a problem?

Fig. 2

- *Calibrate gauges.* Here's another one that was fun to perform. All you had to do was remove the probe from the well and stick it in the pot of oil that was heated by a hot plate. The hot plate could also be used to make a pot of coffee or heat a can of beanie weenies in cold weather. Analog gauges, what could be better, certainly not electronic. So if we ever decide to install some of those new type gauges we better keep the analog in parallel just in case.
- *LTC Internal.* This task was performed by the oil crew. They were the guys (usually 3 to a unit) that were sent to help power factor, ratio and megger if the unit had an ltc. We all remember the ones we didn't mind opening up, especially the vacuum type cause they "usually" didn't have any carbon in them and you didn't go home smelling like burned transformer oil. Our procedure went something like this; drain the oil (don't forget to vent it) into fifty-five gallon drums using a filter press. An apprentice was usually assigned the task of opening the door (hope we drained it all) and wiping everything down before the journeyman did his inspection. That way the senior guy didn't have to get carbon all over him. Look around for parts lying in the bottom and any obvious holes burned in stationary contacts. Also observe if the unit is pretty clean or real dirty. Looks good? Then button it up. Oh yeah, don't forget to fill from the bottom and vent the top

you might break the tap board if you forget and do it backwards. And to think we did this to every ltc (some 800 total) every three years. That's good job justification for at least three people per division X 6 = 18 folks.

- *DGA.* What's that? APCo had begun testing questionable units in the early '80's and again this was the responsibility of the elite equipment test guys. We even had our own gas chromatograph. There were only a couple of folks that even half way understood what those spikes were telling us so they were considered to be real special. But the "old guys" raised opposition to this type test. "I'm doing 877 with my old reliable GE tester (fig. 3) and acid with the vials so why do you want more oil to test?" Later generating plants heard about this new test and asked our environmental lab to start performing test on their units. Reluctantly in 1988 the equipment test guys gave their chromatograph to the lab and wished them luck in interpreting the results. Boy have we come a long way since then.

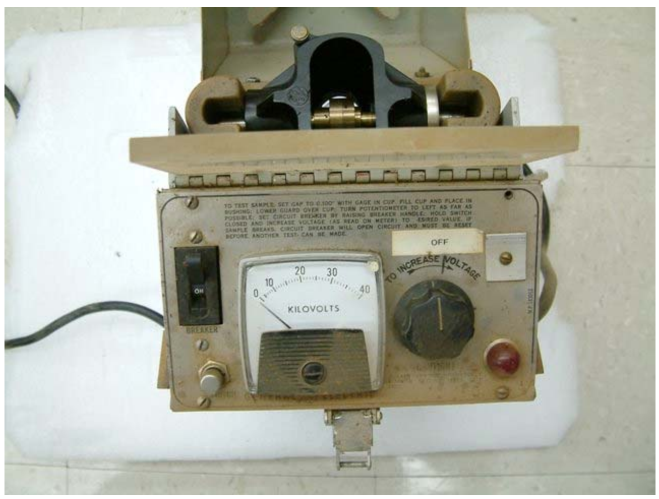

Fig. 3

Condition Based Maintenance, what's that?

During the early '80's chosen engineers were allowed to attend various maintenance and diagnostic conferences and began to bring back stories about a thing call predictive maintenance and other acronyms concerning maintenance that the "old guys" just couldn't understand. They were using words like condition based and RCM. Back then I was a young guy being mentored by and "old guy" and of course I agreed with him when he laughed off these new words. However in 1987 APCo offered an early out package and he laughed right out the door and left me standing there with the deer in the headlight look. Fortunately the supervisor over the equipment test group at that time was one of the folks bringing back the stories and he was excited about the future of maintenance. Unfortunately he became a lawyer in 1992 and left me standing once again with that same looks as when my mentor left. However, before he left he took every opportunity to expose me to everything possible concerning new technology in the transformer business.

Bert Hughes, Ken McDonald, Don Rose, Dan Kroft and Carl Manger are just a few of the “old guys” that I was exposed to during my early days as an equipment test guy. It was kinda like sitting around listening to a bunch of prophets speak when it came to how to maintain and test a transformer. With the exception of Carl, all that wisdom has left the business and turned it over to the rest of us to handle. Were they always right about the old days? Maybe, but then even they had slowly brought some of the new terms into their conversations. Maybe there was something to this condition based maintenance stuff. Maybe we @ APCo should begin to investigate what others were doing and see if we needed to apply it on our system. That sounds well and good to a young guy but we still had a few of the “old guys” left at Alabama and they were resistant to change. Why? Because knowledge is power and “this is the way I was taught to do it so it must be right so forget about what Virginia Power, Texas Utilities and Duke are doing and let me run my own business”. So here’s the challenge for the young guy, try to force new ideas on the “old guys” or simply roll over and play dead. Don’t get me wrong, these were very knowledgeable folks but they had reached a point in their career that they had an opinion regardless of what others thought. Sound familiar?

Best Practices

Alabama Power is just one portion of Southern Company. In 1989 there were five operating companies including Alabama Power, Georgia Power, Gulf Power, Mississippi Power and what was then Savannah Electric. Savannah has since been absorbed by Georgia but for the sake of this story they were still in business when we were told by management that we should get together with the other companies and share our different maintenance practices. This sounded like a reasonable idea until we actually began to sit down and discuss different issues. A select group of substation maintenance personal (one from each company) had been designated to establish a Southern Company wide maintenance philosophy and oh by the way, also save money in the process. One company, one vote, no matter how many employees or customers you had. Over the years we have developed what we feel is the best maintenance practice ever introduced! But this didn’t happen over night, here we are twenty years later and we still meet and discuss where we are and where we should go and each year it seems we get better in our efforts.

By 1992 the five member committee had finalized their proposal for maintenance intervals and what tests should or should not be performed yet all still time based. Procedure manuals were printed and passed along to all the substation maintenance folks on the Southern Company system. This book raised concern by all that received it in that we were about to change the way we did our business. Extend maintenance intervals, eliminate some test and add some others that some of the operating companies had never performed before. The opposition to the new procedures led to the formation of subject matter experts in 1994 for each type of substation equipment and representation from each company. By breaking the different types of equipment into individual groups the individual SME committees could focus directly on their equipment rather than overall general substation maintenance. In 1997 a complete maintenance plan (non flexible) was implemented. In 1998 the maintenance plan was expanded to include flexibility matrices to meet the needs of the individual operating companies. Maintenance activities (time based) were established that consisted of four levels. This provided flexibility in scheduling time based activities with intervals modified by industry experience. This was probably the start of saving money.

We felt we had reached a happy medium between all the operating companies but again it was still time based. By 2000 management had began to ask us to look at areas of maintenance that could be cut or eliminated. We felt we had extended intervals as far as we could without having ramifications from lack of maintenance. Substation managers had to explain to their VP's what would happen if we moved the intervals out further. Our main concern was how to meet reliability requirements and prevent unnecessary outages if we didn't do maintenance. We were kinda behind the rock and the hard place, we had to keep the lights on but do it with less money. This led us to look closer as to what monitoring/diagnostics was out there to help us meet our goals.

Get To The Point!

O.K. enough of background information and get to the title of the paper but it is necessary for you to know where we were in order to understand where we are now. First two definitions are necessary. Predictive; to state or make known about, known in advance, esp. to do so on basis of special knowledge. Maintenance; the work of keeping something in proper condition. So here we are supposed to look into our crystal ball and determine when to do what was necessary to keep a transformer in service using our "special knowledge". So the next part will cover some of the things we've tried since 2000 that actually worked and we have documentation and pictures to prove it. For the sake of time we'll stick to the few simple tests we talked about above individually and the benefits we've seen and dollars saved.

Power Factor

Over the years we had developed quite a database of transformer winding and bushing power factor results.   We began to look at what we were really finding and trending the results by individual families and their application. For example, GE core form, GSU, operating history etc. Another example, Lapp bushing, kV, amp rating, application etc. This allowed us to determine what pieces of equipment need more attention. The above weren't necessarily problems it's just an example of how we broke the equipment down for our study. What did we find? The leading cause of transformer outages other than squirrels or lightning arresters was bushing failure. Also we found by trending that certain models appeared to have no problem while others were bad actors. We rarely blamed an outage or failure on a transformer winding being wet. Also our winding power factor trending results indicated we weren't seeing that many wet units. So where did we focus on power factor testing; bushings. At Alabama we have determined that the transformer oil results including DGA gives us enough information that can extend winding test intervals

ever farther than we had before. We had previously moved from three year intervals to six year and as of 2009 we are at twelve years on all our 500/230 and 230/115kV auto banks. How did we come to this decision, $$$$.

In 2001 we sat down with Victor Sokolov and discussed an idea he had brought to the U.S. concerning on-line power factor testing of bushings and free standing CT's. It seemed that there had been several failures in the Ukraine that had prompted them to look for ways to test more frequently without requiring an outage. It seemed that there were several ways to accomplish including continuous monitoring but we focused on the proven method (20 years experience) used in the Ukraine developed by ZTZ Services. It seemed too simple to be true but once we traveled to the Ukraine and witnessed the on-line test first hand we were convinced it was worth a try at Alabama Power which led to a pilot project with ZTZ Services Intl (4). that has become a standard for all our autos and expanding now into the lower voltage classes. We now have eight years experience with this type test and have determined that we are able to perform important tests and still save money and continue to provide reliable service.

Fig. 4

Papers have been presented before @ TechCon[1] describing how the ZTZ system works so for the sake of time I will stick to the dollar value of the system. As part of our R&D research we have to justify the dollars spent and what is the total value. Our estimate in 2002 was an investment of $665,000.00 over a four year period to install the bushing sensors and terminating boxes on all our large system autos @ Alabama. The total value was estimated to be $2,000,000.00 with a probability for success of 75% which netted us a 225% return on our initial investment. Actually we feel that the project was 100% successful which nets us an even greater return. Now we've made management happy with

the savings but what about reliability? It only requires two people to perform the on-line test so this allows us to test the bad actors more frequently as well as decrease the intervals for all bushing tests. Presently we are on a three year cycle for on-line bushing test and bi-annual for the known problem bushings.

Here's a real example of the advantage of on-line bushing test; After the failure of a 230kV bushing in a 230/115kV single phase auto bank the off-line tests of the sister bushings had increased from their original nameplate value four years earlier. Should we go ahead and replace the sisters or just monitor them closer? The banks had to be back in service ASAP so replacement @ this time seemed impossible[2]. Frequent off-line tests were not really an option due to the time and costs associated with taking the bank out of service every three months as well as the criticality of this particular bank. Figure 5 shows this bank the number of leads that would have to be removed for off-line tests. We opted to install the ZTZ system and perform frequent tests and look at the trend[3].

Fig. 5

The sister bushings were monitored monthly for nine months and did not show a substantial increase in power factor. However due to the questionable initial increase we chose to replace them during a planned outage. Again, another money saver while maintaining reliability.

Currently we have the ZTZ sensors at 125 locations with plans to expand the program as budget allows and sensors are being installed on all capital projects. One particular new customer location has seven 250MVA transformers and we were informed that outages for off-line tests would be almost impossible and that reliability was a must. Therefore we're install sensors on all these units and plan to test the bushings on-line annually. We are still evaluating the money benefit but it certainly outweighs the initial cost.

Transformer Turns Ratio and Megger

Why would one want to take an energized transformer out of service to only perform the above routine tests? Our conventional thinking was that we had to do it because our time based intervals called for it and once the crew folks were trained in how to properly perform the tests they actually enjoyed doing it especially with the new digital devices that didn't require hand cranking. What results were we seeing? Never a change in ratio and a seldom change in the resistance readings. The old method for reenergizing a bank after operation or blown high side fuses required the following things be done.

- Look for anything obvious in the yard that might have caused the problem such as low side breaker failure to operate, lightning damage, smoked insulators or a dead animal. Back in the '70's and early '80's most units carried a dead squirrel around in the truck locker. This served two purposes; an obvious smoking gun if you couldn't find anything else or dinner if you were called out after all the restaurants closed.
- Sniff the gas space on nitrogen blanketed units or look at the gas collector on conservator types.
- Get clearance from the control center and ground out for tests.
- Removed all leads (regardless how many and how heavy) and perform the ratio and megger tests.
- Call the results in to the on call local engineer who then in turn woke up the on call corporate engineer and gave him the results and asked for permission to reenergize the unit. By this time several hours could elapse based on the size of the unit and how far the crew had to travel to test even on radial locations where we had customers out.
- If permission was granted then the lead removal and grounding was reversed and after giving up clearance the unit was energized. Now for a fun note: We had a guy that was a substation engineer in one of the divisions who quite often was in the field calling in the results to the corporate engineer. Later he moved to the corporate function and had to also serve his time as the on call corporate person which gave the local folks permission to reenergize units based on the information they had provided him. What's wrong with this picture?

Today the process after a high side goes something like this:

- The DOC gets an alarm through SCADA
- They look for anything obvious ex. low side breaker failed to operate and an LOL is dispatched.
- If he can verify the cause then the unit is reenergized remotely if equipped with a circuit switcher (standard on all subs since 2004). High side fuses still require substation maintenance folks.
- If a substation crew is necessary, they bring their Kelman Transport (fig. 6)
- Sniff the gas space and if there is no gas reenergize
- If gas is present run a DGA sample on the Kelman
- The on call engineer is notified and he makes the decision to reenergize of if further tests are necessary. Corporate only gets involved if the unit is deemed a failure and a replacement is needed.

Fig. 6

What have we accomplished using the new method?

- Less people involved in the decision making process
- Faster response time
- We're depending a lot more on the non intrusive diagnostics
- Units reenergized quicker than before affecting both revenue and reliability

Calibrate Gauges

This one became fairly simple

- All new units are equipped with the Advance Power Technology TTC 1,000 and anytime we have a problem at an existing site the analogs are replaced with the TTC 1,000. All are tied back to the DOC through SCADA giving us real-time information.
- Currently all station with 230kV high side and greater and GSUs are scanned annually with an infrared camera. Locations < 230kV are scanned on a three year cycle. While performing the scan the technician verifies the top oil temperature by scan adjacent to the probe and comparing it to the actual gauge reading. Anything > 5° C out is reported to the maintenance area for investigation. What are we saving? Manpower and trips to a location just to calibrate gauges which in some cases are a long ways from crew headquarters. This equal $$$ savings by actually doing predictive maintenance.

LTC Internal Inspection

As stated earlier in the early ‘80’s we were doing internals on 800 tap changers on a three year interval. In 1992 we extended those intervals to six years and suffered the consequences. We learned that certain families of tap changers just couldn’t go that long leading to unexpected outages and sometimes winding damage in the main tank. In 1996 we began a pilot program of DGA on LTCs looking only at key gasses. We soon learned that there is no exact limit for tap changers generically. It was obvious that each family had their own gassing patterns and there were other gasses to look at other than ethylene. So we began to sort all ltcs by mfr. then type and gassing pattern. That was an eye opener for us. It appeared that some units could have high levels of C2H4 and not have a problem while others showed signs of problems with C2H4 levels < 1000 ppm (fig 7 & 8). From 1996 until 2004 we opened up approximately 32 units per year based on the gasses in addition to those on normal six year cycle internals. Were we saving money? Not really but we felt we were preventing unnecessary outages. We had a few false positives and used those to determine what levels we should really be looking for. Using this information we switched from time based to condition based in 2005. Now we began to see savings of maintenance dollars but still had a couple of unexpected failures.

Fig 7

Sample ID	Col Date	Moisture	Acetylene	Hydrogen	CO	Ethylene	Ethane	Methane	T Comb
AD08544	3/9/1999	0.0046	27.	56.	290	212.	69.	116.	770.
AE05120	2/15/2000	0.0042	12.	ND	14	121.	24.	18.	189.
AF15220	5/17/2001	0.0050	33.	ND	81	6.	ND	3.	123.
AF24786	8/27/2001	0.0050	34.	13.	45	5.	ND	ND	97.
AF25346	8/29/2001	0.0057	331.	23.	54	155.	12.	44.	619.
AG04111	2/11/2002	0.0026	93.	ND	41	296.	43.	53.	526.
AH10065	3/28/2003	0.0034	116.	ND	69	29.	4.	6.	224.
AI06580	3/3/2004	0.0034	13.	ND	31	3.	ND	ND	47.
AJ29769	11/8/2005	0.0073	15.	ND	35	3.	ND	ND	53.
AK21631	8/7/2006	0.0054	31.	29.	340	17.	3.	14.	434.
AL17971	6/18/2007	0.0046	22.	31.	339	66.	13.	25.	496.
AM06011	2/27/2008	0.0021	3.	44.	292	587.	206.	279.	1411.
AM26158	9/15/2008	0.0039	57.	ND	45	14.	ND	4.	120.

Fig 8

Here we are twelve years after start of the pilot project and in 2008 we opened up only thirteen units based on gassing alone and had only two failures that were both mechanical. How did we come to this point? Lyndal Cost, one of the equipment test specialist researched everything he could find on established gas ratios for ltcs. Using this information he methodically established his own set of ratios. No tap changers are opened up until Lyndal makes the call. Also we saw such value in the DGA program that we went from annual sampling to twice per year, once before summer peaks and then again in the fall after the load. What do we accomplish by bi-annual sampling? We've found that problems can be found in advance and not wait until July 4th for the unit to bring itself out. Also, it appears that some units just can't stand the peak loading so we get into those immediately after the summer peaks. It has been estimated that we are seeing a savings of $400,000.00 per year plus reliability has been increased.

In addition to the DGA analysis we determined that on-line filtration of ltcs was also of extreme value in extending maintenance intervals. As an example we had two 15kV UTT units operating on a 22kV system (questionable application) that required internal inspection every nine months or there would be a flashover across the tap board leads due to the amount of carbon generated in the tank. Filtration was installed on these units in 1998 and they were not opened up until 2000 just out of curiosity. Both units were clean and no obvious sign of excessive carbon. These units have not been opened since 2000 and the DGA results remain at low levels.

In 2006 we partnered with Parker Filtration (fig. 9) to develop a bare bones ltc particle filter with absolutely no bells or whistles other than a pressure differential switch that would first give an alarm and then shut the system down at a predetermined value. We simply turn the units on and let them run continuously. We are installing these systems on all existing arcing units (600 total) anytime the units is out for some other reason. We have them installed on approximately 200 units and have seen benefits on all installations. Another simple solution to excessive H2 levels is to make all arcing units free breathers. Prior to 2006 we had at least three locations where the tap board had been damaged due to pressure caused by a stopped up vacuum/pressure bleeder. If the dirt daubers don't get you then the painters will. Today we are installing a simple disposable breather filter (fig. 10) on all these arcing units which has resulted in payback with the decrease in total gas. The ratios still remain the same it's just that the units are now operating at lower gassing levels.

Fig. 9

Fig. 10

Our new “not time based interval” philosophy for tap changer maintenance is something like this; keep them dry, keep them clean, let them breathe, ensure they pass through neutral, monitor using DGA and leave them alone!

Dissolved Gas Analysis

Back to 1992, remember my boss who happened to the DGA expert at APCo was about to leave me holding the bag and go on to his new career. He apparently didn’t want to leave me clueless on this topic and suggested we attend a small seminar in New Orleans concerning dissolved gas analysis. This was my first real close up exposure to Ted Haupert and I decided this guy must be some kind of “nut”. How could anybody get so excited about transformer oil that would cause them to break wooden pointers on the projection screen and walk about the room like a madman. Today, while I don’t have the gas expertise as Ted and several others I now share some of that same enthusiasm and still feel the same way I did in 2005[4] . If we could only have one tool in our toolbox concerning transformers it would be DGA. It’s the EKG that tells us where we should go next in evaluating the condition of our transformers.

Currently we’re on an annual cycle for >46kV transformers and quarterly for GSU units. Including the ltc analysis our lab runs about 7,500 samples per year. Imbedded software flags the questionable units and electronic detailed reports sent to the six maintenance areas and plants. We have provided training to the maintenance areas in interpreting the results and our group only gets copied on the bad actors. What are the savings using this technology? I don’t have a clue but it only takes a couple of $4,000,000.00 transformer saves to convince management we are on the right track.

What’s Next?

The above are just a few of the examples of were we are with predictive maintenance. We're using some of the latest technology for condition assessment of other pieces of equipment such as circuit breaker and instrument with some of the same success we're seeing with transformers but those are outside the scope of this paper.

Future plans include installation of Kelman Transfix units on all large GSU and system tie units. We currently have ten Transfix units installed and the initial cost has proven to be offset by the ability to continuously monitor these units. Also the ZTZ bushing monitoring system is being expanded to include continuous monitoring with built in analysis software and alarm outputs.

A pilot project consist of what's being called a "data historian" with output from all our monitoring devices to a central computer that can be accessed by the responsible folks in each maintenance area. Hopefully this will be a topic at a future TechCon.

Conclusion

At this time I don't have a conclusion because we're continuously searching for new ideas in equipment monitoring. However, we feel that the above topics are a start to what we consider to be predictive solution while still saving $$$. What is the down side to this savings? It seems that each time we come up with a money saver that doesn't impact reliability upper management decides "o.k. they did good with that one so let's challenge them to find something else new buy cutting their maintenance money again". When will it end?

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