TURBINE PROTECTION SYSTEM PERFORMANCE

by

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ABSTRACT

The need to protect a turbine generator from abnormal operating condidtions is a given. Power plant operational historical data indicate that malfunction of the turbine protection system (TPS) has been the initiator of many power plant trips and attendant losses of plant availability. Many of these documented events have been considered to be caused by improper or faulty action of sensors leading to false trip conditions.

Whether in a petrochemical or nuclear power plant, the design and operation of the TPS is fairly consistent. It is logical to consider, therefore, that the unreliabilities found within the TPS at nuclear power plants will be similar to those found at petrochemical facilities.

Statistical methods of analysis to quantify the unreliability of TPS components are considered, along with the magnitude and root causes of lost availability attributable to the spurious functioning of the TPS at nuclear power plants; identification of corrective actions such as sensor replacement, multiple logic and artificial intelligence; and methods of analysis to quantify the reliability improvements which will result from these corrective actions.

INTRODUCTION

Nuclear industry data bases report that turbine related failures account for approximately one unplanned forced outage per plant per year [1]. Of the many turbine subsystems and components, the turbine protection system (TPS), or more specifically, the electrohydraulic controls systems (EHC), has been identified as a principal source for spurious turbine trips. The EHC system is the backbone of the turbine protection system, connecting critical turbine components with the automatic turbine trip relay. Although new turbine protection systems are implementing wholly digital systems with distributed microprocessor based control, the majority of the installed turbine protection systems rely on the high pressure pneumatic EHC system. To supplement the protection afforded by the this system, most suppliers also provide a comprehensive package of turbine supervisory instrumentation (TSI) systems. These TSI systems can be designed, at the request of the customer, to initiate protective actions.

Power plant experience indicates that the turbine protection systems often initiate turbine trips when operating conditions do not warrant a trip. In Table 1, the Institute of Nuclear Power Operations (INPO) reports the listing of subsystems and components that are typically associated with turbine trip events [2].

Table 1. Subsystems and Components Typically Associated with Turbine Trip Events.

Subsystem	Percent of Total Turbine Trip Events
EHC System	47
Governor/Control Valves	9
Intercept/Stop Valves	6
Instruments	5
Pressure Regulator	5
Bearings	3
Oil System	3
Shafts/Blades	3
Miscellaneous or Unknown	20

Clearly, it would be most desirable to eliminate spurious turbine trips, but not at the expense of proper protective functions. The dangers both to operating personnel and to plant equipment posed by turbine overspeed, shaft vibration, loss of lubricating oil, etc., are very real, and should be reliably detected and avoided through comprehensive protection systems. False trip conditions, however, should be positively identified, and needless turbine trips should be avoided to the maximum extent possible.

Research reported herein was sponsored by the Electric Power Research Institute and the New York Power Authority to investigate the numerous false turbine trip events which have plagued the nuclear industry, and to suggest equipment and/or techniques which can improve TPS performance and reliability in a cost beneficial manner.

DISCUSSION

Root Cause Analysis

To identify the magnitude and root causes of lost availability attributable to the spurious function of the TPS, detailed analyses were conducted using industry data bases of nuclear power plant operating histories. Data from approximately 80 plants covering the years 1978 through 1985 were included in the evaluation. In all, over 340 years of nuclear power plant turbine operating history was studied. A statistical analysis of the data, augmented by an industry survey and utility interviews, led to identification of areas within the TPS which could benefit from retrofit of corrective actions.

The data were divided into groups based on the cause of the event. These groupings were further manipulated to obtain the equivalent outage hours expected to result from each type of spurious event. The expected outage hours were determined by examining the performace parameter, equivalent full power hours (EFPH) lost, which is recorded for each event. The EFPH lost is the percent capacity lost due to an event multiplied by the duration of the event in hours. For example, an event that causes a 20 percent power derating and lasts for five hours would have an EFPH of one hour.

The EFPH is a function of the outage duration and is therefore essentially "repair time." From experience it is known that repair time data follow the exponential probability distribution. Switch failure data are shown plotted in histogram form in Figure 1, and the curve drawn along the histogram indeed follows an exponential probability distribution. Since the failure data are exponential, the EFPH expected to result from the occurrence of a switch failure is best represented by the median, not the mean, of the data. Using the median value of each root cause grouping, the amount of EFPH expected to result from each failure type was determined. Finally, the EFPH expected to be lost annually by each operating nuclear plant was calculated. The results of these calculations are given in Table 2.

An economic analysis of the worth, in terms of replacement power costs due to more reliable TPS operation, led to the conclusion that elimination of six to eight hours of lost power generation would justify an expenditure of roughly $700,000 on TPS improvements.

Table 2. Lost Power Generation due to Spurious TPS Events.

Root Cause	Expected EFPH Lost per Event	Expected EFPH Lost (hr/yr/plant)
Vibration	32.2	1.02
Circuit Card	24.0	1.04
Stop Valve	13.0	2.02
Main Steam Bypass Valve	13.0	0.59
Switch	12.0	0.76
Personnel Error	12.0	2.76
Other Electrical	8.9	0.33
Relay	7.5	0.19
Control Valve	5.0	1.48
Turbine Overspeed Test	2.9	1.44
Valve Test	1.1	5.20

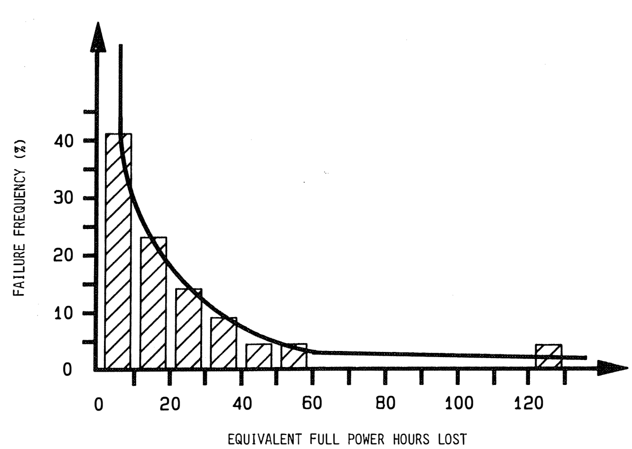

Figure 1. Histogram of Switch Failures.

Potential Corrective Actions

Numerous hardware modifications are available to increase TPS reliability. The following presents possible corrective actions for TPS problem areas identified through the preceding statistical analysis, and some methods of quantifying the reliability improvement to be gained through implementation of the suggested corrective actions.

Improved Sensor Performance

TPS reliability can be improved by replacing certain troublesome sensors whose malfunctions were frequently noted. A sensor may be replaced-in-kind or with an improved sensor whose design is intended to preclude previously observed difficulties inherent in the older design. Replacement of a troublesome sensor with a new (but same model) sensor will provide immediate performance improvement; however, if the original sensor malfunctions are due to worn materials or other similar problems, long-term performance improvement of this sensor can only be realized through application of a more aggressive preventive maintenance program.

Beyond replacement-in-kind is replacement of a problem-prone sensor with a unit which is technically superior, e.g., replacing a level sensor having moving internals with a unit which senses level via a conductance measurement. A typical example is shown in Figure 2. In the latter case, there are no moving parts, and, therefore, less likelihood of sensor failure or false measurement.

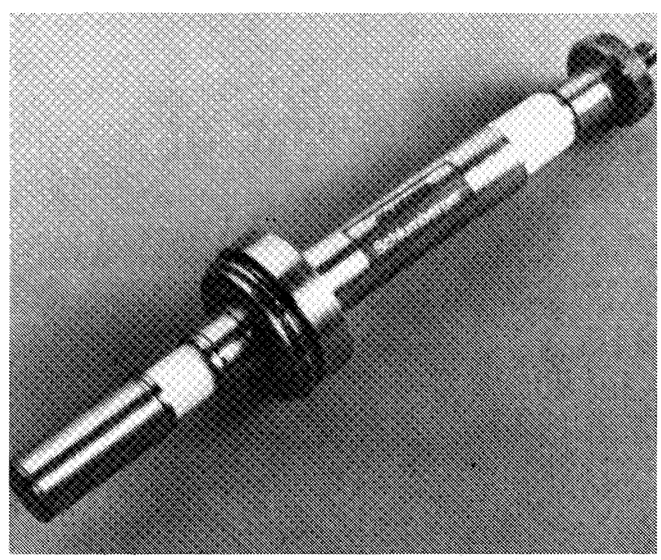

Figure 2. Hydratect Resistivity Electrode.

Another sensor that often malfunctions due to mechanical wear is the shaft-riding vibration probe. Shown in Figure 3, the typical shaft-rider has a spring-loaded tip which rides against the shaft surface. It was the failure of this spring at one nuclear plant that resulted in a forced outage which lasted for about 100 hr, and in replacement power on the order of $120,000.

One corrective action that could improve TPS reliability and offer greater equipment diagnostic capability would be the replacement of the shaft-riding vibration detector with the eddy current type proximity probe. Intuitively, the noncontacting proximity probe is expected to provide better performance than the traditional contacting type vibration probe. In addition to

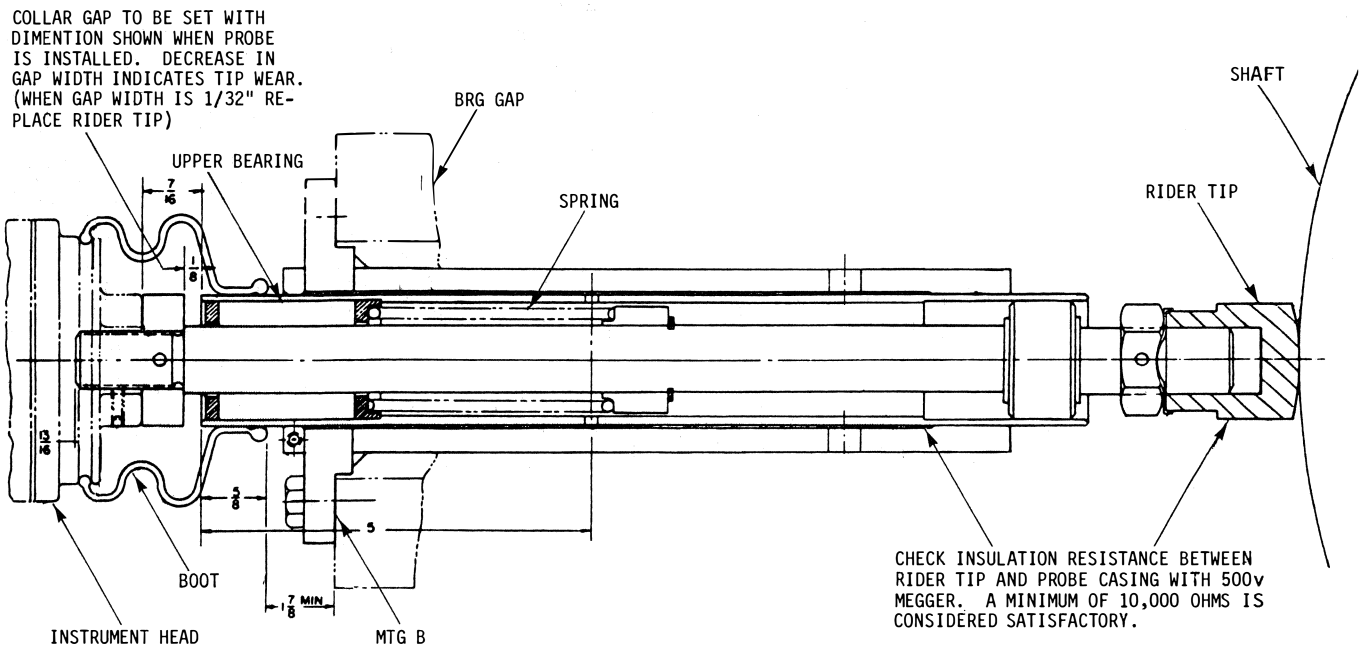

Figure 3. Shaft-Riding Vibration Probe.

mechanical wear, the shaft-riding probe design has some other disadvantages. Operation of the shaft-riding probe relies upon proper lubrication to prevent chattering, slipping, or bouncing of the probe on the turbine shaft. The probe tip must be replaced regularly, and internal components such as the spring that loads the rider tip and the spring guides can be affected by fatigue. Cyclic loading may change the spring constant or result in sudden failure. The probes may also stick, giving false low vibration readings, leaving the turbine unprotected.

The eddy current proximity probe has some advantages over the shaft-riding probe. The proximity probe has the ability to detect rotor bow, eccentricity, and zero speed at low rpm. The available operational data on these two probe types are somewhat incomplete, but indications are that the proximity probe is replacing the shaft-rider on an industry wide basis and that the proximity probe has, in its short history, provided reliable operation.

Relay Upgrade

The mercury-wetted relay has been reported as a problem component in nuclear plant operational history. There are approximately 30 of these mercury relays in a typical TPS, each of which is hardwired to trip the turbine. Each relay is arranged in a 1-out-of-1 trip logic, so that the failure of any of the 30 relays can result in either a spurious turbine trip or a failure to trip when required.

A relay manufacturer representative commented that the relay model is a highly reliable "workhorse" that can withstand millions of cycles. The relay is commonly selected today because of its high cycle life and quick response time. The manufacturer also commented that, although it is unusual, some customers have reported that the relay will stick in position if it has been sitting de-energized for a period of time. Since, in the application of TPS these relays can be de-energized for months at a time, the use of the high cycle life, mercury-wetted relay in this system appears to be a misapplication. Extensive bench test data are available to prove the relay's outstanding performance over millions of cycles; however, no data are available from the manufacturer on the relay performance in applications such as in the EHC system where the relay is infrequently cycled.

Since the mercury-wetted relay fails in the as-is position, the addition of a time delay to the circuit would not solve the problem. However, replacing the mercury-wetted relay with a more reliable solid-state relay would be one method of improving the TPS reliability and eliminating a problem component. The selected solid-state device would have to accept dc voltage and allow only unidirectional current flow. A silicon controlled rectifier (SCR) is one solid-state device that could meet these specifications. The system modification, however, is not just the simple replacement of the mercury relay with the SCR. The SCR operates at a low voltage level (~3 Vdc), therefore, a high value resistor would have to be included in series with the SCR to reduce the voltage drop across the SCR. Another circuit design change necessary if an SCR were used would be a modification to the master reset circuit. A manual pushbutton reset would have to be added to open the 24 Vdc bus, interrupt the flow of current, and thus reset the SCR. Figure 4 shows a typical Mark I EHC trip circuit, and Figure 5 shows the same circuit with the SCR incorporated. The circuit redesign as shown in Figure 5 has an additional feature in that the illumination of the indicator light is reversed from its original design. The light will be energized when the system is tripped.

Another solid-state device that could be used to replace the mercury-wetted relay in the EHC trip logic is the metal-oxide semiconductor field-effect transistor (MOSFET). The use of the MOSFET would, like the SCR, require the use of a high value resistor to reduce the voltage across the semiconductor. The MOSFET operation is similar to any transistor and would not require the incorporation of the master reset in the 24 Vdc bus.

The replacement of the mercury-wetted relays which are displaying a "fail as-is" type of failure mode with either a SCR or MOSFET will improve the trip system reliability by a factor relevant to the improvement of the component failure rate. Reliability data from IEEE Standard 500 [3] gives the following failure rates, λ:

Mercury-wetted relay	$\lambda = 2.41/10^6$ failures/hr
Solid-state relay	$\lambda = 0.69/10^6$ failures/hr

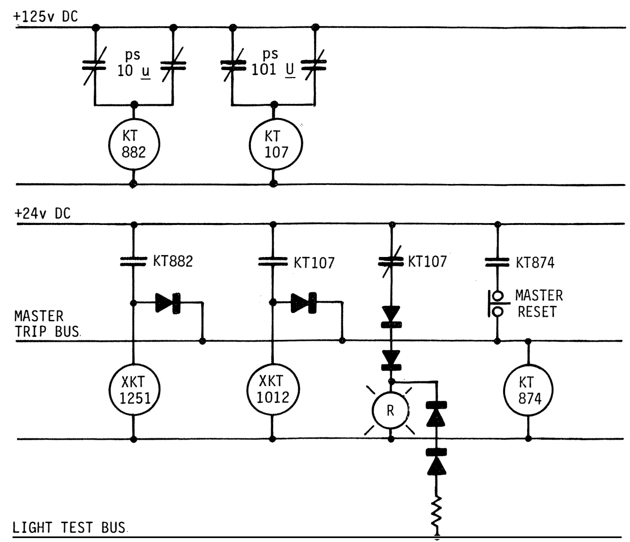

Figure 4. Typical Trip and Reset Circuit within Existing TPS.

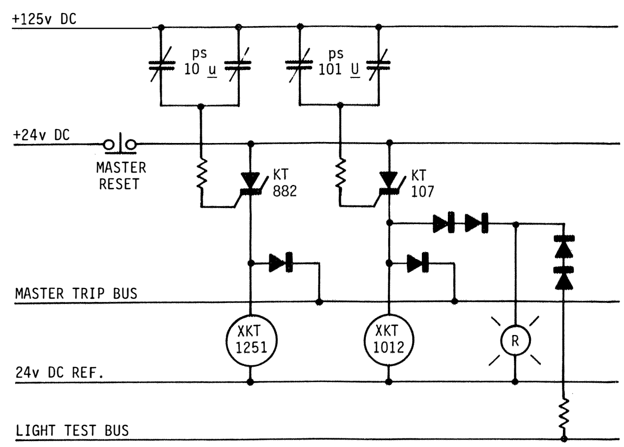

Figure 5. TPS Trip and Reset Circuit Modification-SCR Replacement of Mercury Relay.

These failure rates relate to the probability of successful operation (P_s) of the relay. This relationship is presented in Equation (1).

$$P_s = e^{-(\lambda td)} \tag{1}$$

where

t = mission time
d = duty cycle factor = operating time/mission time

Over an operational period of one year, the duty cycle factor will remain the same regardless of the relay type and the operating time will be taken as period hours of 8760 hr/yr. Using the failure rates presented above, the reliability improvement (or increase in the probability of successful operation) of the solid-state device over the mercury relay is determined:

$$\Delta P_s = e^{-(0.69 \times 10^{-6} \times 8760)} - e^{-(2.41 \times 10^{-6} \times 8760)} = 0.015$$

In other words, the probability of successful operation of the solid-state relay is 1.5 percent greater than the probability of successful operation of the mechanical mercury relay. To relate this 1.5 percent reliability increase to tangible values, one must consider that there are 30 affected relays operating in a station with approximately 30 years of operating life remaining, then the number of mercury-wetted and solid-state relay failures to be expected from the TPS during the remaining life of the plant can be calculated.

- Number of mercury-wetted relay failures
  $= 2.41 \times 10^{-6}$ (failures/hr) $\times$ 8760 (hr/yr) $\times$ 30 (yr) $\times$ 30 (relays)
  = 19.00 failures
- Number of solid-state relay failures
  $= 0.69 \times 10^{-6}$ (failures/hr) $\times$ 8760 (hr/yr) $\times$ 30 (yr) $\times$ 30 (relays)
  = 5.44 failures.

From these calculations, it is found that the 1.5 percent reliability improvement resulting from replaceing 30 mercury relay with 30 SCRs equates to the prevention of 13.56 failures over a 30 year plant life. It has been determined that if a relay failure occurs it will result, on average, in 7.5 EFPH of lost generation. Therefore, this suggested modification could result in 102 hr of additional power generation in a 30 year plant life or 3.4 hr of additional full power generation each year.

Multiple Logic

An alternative to simply replacing a troublesome sensor with another is to improve system reliability by adding a second, or even a third, similar sensor. With additional sensors, it is possible to change the logic so that each sensor votes on the parameter being measured. Using Boolean logic and truth tables, the relative reliability of multiple logic configurations can be evaluated. To illustrate, these analytical techniques are used to evaluate multiple logic configurations for turbine vibration detection.

The possible operational states for a vibration detector are as follows:

f_0 = The sensor is operating correctly
f_1 = The sensor is not operational, giving no signal or a signal that is recognizably incorrect
f_2 = The sensor output is lower than it should be. This sensor state could lead to an undetected failure
f_3 = The sensor output is higher than it should be. This sensor state could lead to a spurious trip.

Truth tables can be used to illustrate the effects of the numerous sensor states associated with multiple logic arrangements. The matrices shown in Figures 6 and 7 give all possible combinations of sensor states for 1-out-of-2 and 2-out-of-2 logic, respectively. The consequences or conditions resulting from each possible combination of sensor states are indicated graphically. Using these graphical presentations, mathematical expressions were derived that define the probabilities of critical events occurring for each multiple logic scheme. These are presented in Table 3.

Since the actual probabilities of occurrence of the sensor states for the proximity probe are unknown, with caution and educated experience, these probabilities must be assumed. The relative performance of the multiple logic configurations is highly sensitive to the relative probabilities of the four sensor states, and slight changes in the assumed probabilities for sensor states can radically alter the recommendation for a particular multiple logic format.

To increase confidence in the quantitative assumptions made regarding sensor state probabilities, manufacturers and service companies familiar with the proximity probe vibration monitoring system were contacted and questioned about the failure modes most commonly experienced with this type of vibration detector. Specifically, representatives from Bentley Nevada, IRD, and Mechanical

Table 3. Critical Event Probabilities for Multiple Logic Arrangements.

	Single Sensor	One-Out-of-Two Logic	Two-Out-of-Two Logic	Two-Out-of-Three Logic
Probability of Correct Operation	$P(f_0)$	$P(f_0)[1 + P(f_1) + P(f_2) - P(f_3)]$	$P(f_0)[P(f_0) + 2P(f_3)]$	$3P(f_0)^2 - 2P(f_0)^3 + 6P(f_0) \times P(f_3)[P(f_1) + P(f_2)]$
Probability of Condition Allowing Undetected Failure	$P(f_2)$	$P(f_2)[P(f_2) + 2P(f_1)]$	$P(f_2)[P(f_2) + 2P(f_0) + 2P(f_3)]$	$3P(f_2)^2 - 2P(f_2)^3 + 6P(f_1)P(f_2)[P(f_0) + P(f_3)]$
Probability of Condition Requiring Provisional Trip			$2P(f_1)[1 - P(f_1)]$	$3 \times P(f_1)^2P(f_0)$
Probability of Condition Allowing Spurious Trip (Lower Bound)	$P(f_1)$	$P(f_1) \times P(f_1)$	$P(f_1) \times P(f_1)$	$P(f_1)^3 + 3P(f_1)^2[P(f_2) + P(f_3)]$
Probability of Condition Allowing Spurious Trip (Upper Bound)	$P(f_1) + P(f_3)$	$P(f_1) \times P(f_1) + P(f_3)[2 - P(f_3)]$	$P(f_1) \times P(f_1) + P(f_3) \times P(f_3)$	$P(f_1)^3 + 3P(f_1)^2[P(F_2) + P(f_3)] + 3P(f_3)^2 - 2P(f_3)^3$

Table 4. Calculation of State Probabilities.

	1-out-of-1	1-out-of-2	2-out-of-2
Probability of correct operation	0.985	0.996820	0.973180
Probability of condition allowing undetected failure	0.00450	0.000101	0.008899
Probability of condition requiring provisional trip (investigation at sensors)	0.0	0.0	0.017838
Probability of condition allowing spurious trip	0.01050	0.003079	0.000083

Dynamics Analysis, were contacted. There was a consensus among these specialists in vibration monitoring and diagnositcs that the proximity probe system most commonly fails with an open or short circuit, resulting in the probe sending zero ac signal. Additionally, some failures have resulted when the probe backs out of its threaded position increasing the gap to a point where no reading is received. Interviewees reported that it is extremely unlikely that the system would give a false high signal, but that a partial short could result in a false low signal. Based on the judgements of these experts, the state probabilities of the proximity probe vibration monitoring system can be more realistically selected as:

$$P(f_0) = 0.985$$
$$P(f_1) = 0.009$$
$$P(f_2) = 0.0045$$
$$P(f_3) = 0.0015$$

By substituting these sensor state probabilities into the probability equations given in Table 3, the relative value of the logic configurations can be determined. The calculated probabilities are given in Table 4.

Further consideration must be given to these calculated probabilities. Table 4 shows that the 2-out-of-2 logic arrangement is under a provisional trip condition 1.8 percent of its operating time. During this provisional trip period, the operator will be aware of a single sensor failure, but will not automatically trip the turbine.

It is practical to consider that the six upset, provisional trip states shown in Figure 7 will actually result in other operating states. For example, consider the upset condition when one sensor is okay and the second sensor is known to be giving an incorrect signal. Under these circumstances, it is most likely that the operators will act correctly to investigate and repair the faulty sensor and will manually monitor the second, good sensor to protect the turbine. It can be reasonably assumed that this occurrence results in continuous successful operation of the turbine. Therefore, the probability of occurrence of this system

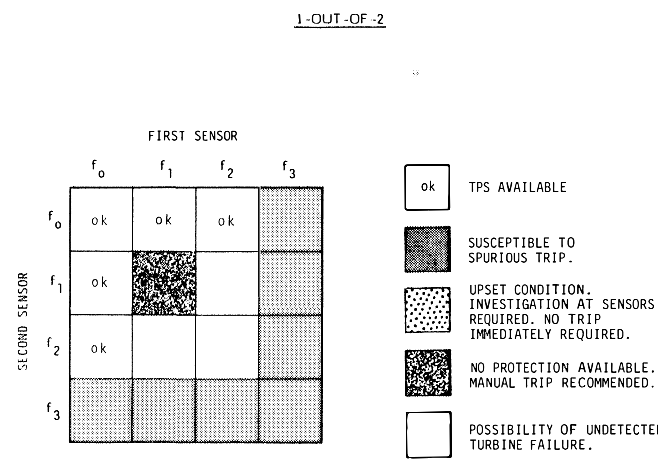

Figure 6. State Combinations 1-Out-of-2 Logic.

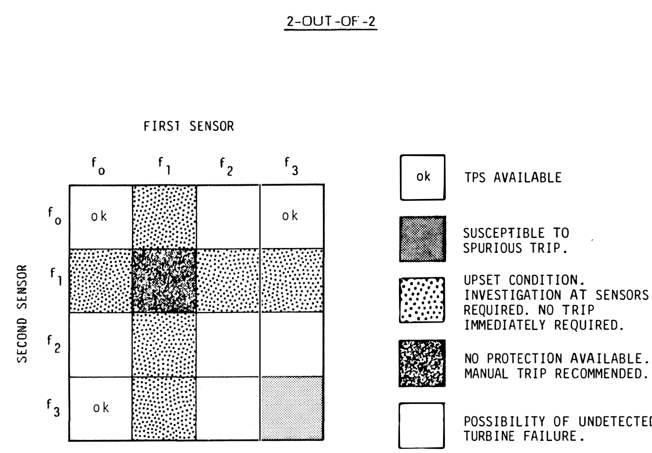

Figure 7. State Combinations 2-Out-of-2 Logic.

upset state is added to the probability of system success. The system is in another upset condition where one sensor is *known* to be giving a wrong signal and the second sensor is indicating a false low signal. In this case, the system has left the turbine susceptible to an undetected failure, because the operator will be monitoring the one sensor that he believes is correct and will not be receiving a true reading. The probability of this system state is added to the probability of an undetected failure. Following this logic for the six system upset conditions in the truth table, the probabilities of occurrence of the four state probabilities for the 2-out-of-2 logic can be revised. A comparison of these modified probabilities with the other logic configurations is presented in Table 5.

Table 5. Modified Calculation of State Probabilities.

	1-out-of-1	1-out-of-2	2-out-of-2
Probability of correct operation	0.985	0.996820	0.99090
Probability of condition allowing undetected failure	0.00450	0.000101	0.008980
Probability of condition requiring provisional trip (investigation at sensors)	0.0	0.0	0.000
Probability of condition allowing spurious trip	0.01050	0.003079	0.00011

The modified state probabilities indicate that with appropriate action from the operators the 2-out-of-2 logic configuration is more likely to succeed than just a 1-out-of-1 logic, but is slightly less likely to succeed than the 1-out-of-2 logic. The 2-out-of-2 configuration provides superior defense against spurious turbine trips but is more susceptible to an undetected failure than the 1-out-of-2 logic.

The probability of the protection system failing such that the turbine is vulnerable to the occurrence of an undetected failure is highest in the 2-out-of-2 logic; however, for this vulnerability to result in an actual undetected failure, an actual high vibration must simultaneously occur with this sensor state. Therefore, the absolute probability of an undetected high vibration is reduced. On the other hand, it is not necessary for a turbine failure to occur coincident with a vibration probe failure for a spurious turbine trip to result. Hence, the possibility of the single sensor failure resulting in a spurious turbine trip presented by both the 1-out-of-1 and 1-out-of-2 logic schemes should be a greater concern than the potential of one undetected failure posed by the 2-out-of-2 logic. *Neither the 1-out-of-1 nor the 1-out-of-2 logic schemes would address the problem of spurious trips better than the 2-out-of-2 logic format.*

Incorporation of two proximity probes would also reduce repetitive maintenance requirements during refueling outages. Removal of the shaft riders would eliminate the maintenance associated with the replacement of the shaft-rider probe tip. It is estimated that the calibration of the proximity probe would not require any more time than is needed for the shaft-rider system. In fact, the proximity probe is easily calibrated in place once the turbine shaft is at a standstill.

Specialty Instrumentation

One unique protective system that has been broadly applied in the petrochemical industry to ensure safe, reliable protection and control of refinery equipment is the PRETECT system [4]. This system has been designed by Trip-A-Larm Corporation to *completely eliminate* equipment outages caused by spurious trips. The claim is that, at least in the petrochemical field, about 95 percent of system trips observed are caused by faulty sensor readings. This system has reported up to eight years of operation in a large number of petrochemical facilities without causing a spurious trip. There has been only one utility application, however, which was a fossil-fired power station for boiler protection and control.

This system employs an end-of-line device (ELD), a complementary metal oxide semiconductor (CMOS) that is retrofit as close as possible to each existing sensor (see Figure 8). Each ELD is fed a constant dc input voltage, and its output dc voltage level provides an indication of fault conditions around the sensor. Specifically, wiring between the ELD and the signal processing logic is continuously monitored for:

- Short circuits
- Open circuits
- Ground faults.

Wiring beyond the ELD is monitored only for ground faults. For any fault condition, visual and audio annunciation alerts the operator of the condition. Similarly, in the event of a defective logic card, a yellow light illuminates a window stating "card fault." Such detailed information assists the operator in identifying system disturbances that could otherwise be mistaken as a condition warranting trip.

The system contains other features and options such as optional voting logic, time delay to protect against contact bounce, on-line testing of circuit cards, first out indication, and all military grade componentry.

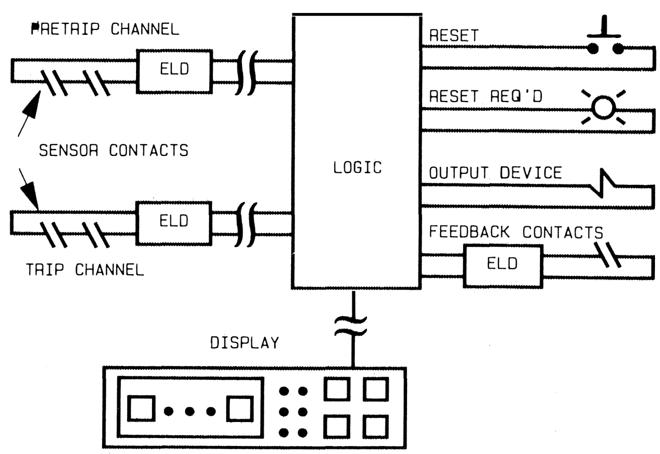

Figure 8. ELD Installation Schematic.

Future TPS Techniques

The previously discussed corrective actions have the potential for producing improved TPS reliability in a cost-beneficial manner. There are other approaches to TPS performance improvement, either under development or close to commercial availability, which will likely form the framework for future TPS designs. Commercial costs were difficult to obtain, given the developmental nature of most of these approaches, so cost benefit could not be accurately determined. However, it is felt that turbines will almost assuredly be protected by using some of these schemes in the not-too-distant future.

Artificial Intelligence Expert Systems

Turbine AID

Westinghouse Large Steam Turbine Division has developed an artificial intelligence (AI)-based diagnosis system for analyzing turbines on-line and identifying potential problems. The system detects changes in operating characteristics, and evaluates such changes against an extensive rule base to decide whether or not the observed abnormality requires attention. The turbine AI diagnostic (Turbine AID) [5] system monitors operational parameters using existing plant sensors, with other sensors being added as required to form the necessary set of inputs to the AI software. A plant data center functions both as a local monitoring system and a data acquisition center. From the plant data center, operational data are transmitted continuously, via modem, to the centralized diagnostic center located at Westinghouse Power Generation headquarters. At the diagnostic center, software called PDS (process diagnostic system) translates the sensor inputs into a diagnosis and recommends corrective action if an abnormal condition exists. Each recommendation is coupled with a corresponding confidence factor (cf) in the range of $+1$ to -1. The diagnosis, recommendation, and cf are then transmitted back to the plant data center and the operator.

The diagnostic center is staffed 24 hr/day with turbine specialists who can assist the plant operators with symptom diagnosis if the condition has never been seen before. These new episodes will then be entered into the rule base, so that a similar condition occurring at another plant can be quickly diagnosed by the computerized expert system.

The PDS software has been applied to the diagnosis of generator operation since 1984. The system, called GenAID, was under development for over nine years and required the use of over 10,000 rules. Seven power stations are currently connected to the GenAID system, and reports of its performance are favorable.

Turbine AID does not provide turbine protection in the traditional sense. Many events causing turbine failure occur so quickly that nothing but immediate action, such as tripping the turbine, can prevent damage to the turbine. The Turbine AID system does not add redundancy to the existing sensing elements, nor does it eliminate the need for automatic tripping action on certain indications. However, this system potentially can provide significant savings by providing outputs in the form of either directed maintenance tasks or information regarding observed abnormal trending, both of which are intended to head off turbine failures before they can occur.

TURBOMAC

Radian Corporation has applied its expert-system software, RuleMaster, to develop an expert system, TURBOMAC, [6] to assist in the diagnosis of vibration in turbomachinery. The focus on vibration diagnosis is because most difficulties with turbomachinery manifest themselves by some form of vibration.

This menu-driven system allows nonprogrammers to create rules from examples; advanced users can create rules from scratch. It will explain reasoning on demand and can handle uncertainty. Data from field sensors are manually entered into the system by plant operators. The system asks the operator questions until it has sufficient information to make a diagnosis. Information from other data bases can also be entered to assist in the diagnosis. The system can be programmed to initiate responsive actions, such as turbine trip, given an appropriate diagnosis.

Ultimately, the system will be configured so that the diagnostic software remains in a central location, and each plant is connected to it through a modem. However, the system is *not* intended to be an online continuous monitoring system, but to be operated only when considered necessary by a plant operator. According to its developers, this feature will give plant personnel a feeling of autonomy which may be absent when using a continuous plant monitoring system with monitoring by an outside party.

The effectiveness of the system has not been demonstrated by operation in actual plant environments, and the reliability improvement expected from its use is unknown. It is expected, however, to effectively reduce the time and manpower required for accurate diagnoses of vibrational problems in turbines.

Expert System for Machinery Diagnostics

Recognizing the possible improvements in plant availability from equipment monitoring and diagnosis, Shaker Research Corporation has developed an expert system for on-line machinery diagnostics [7].

Although the knowledge-based system developed under this EPRI research project is limited to a vibration diagnostics system for pumps, it can easily be extended for application to turbine shaft vibration diagnosis. Unlike efforts based on pattern recognition, the EPRI system is designed to imitate an experienced machinery vibration analyst by virtually automating the logic and decision making process.

This online continuous monitoring system uses existing field sensors, but may require the addition of sensors for more data input. It also incorporates data from machinery models. The system analyzes both short-term and long-term changes in vibration data, and diagnoses malfunctions using a rule base made up of the analysts' deductive reasoning. Many years of troubleshooting experience were used to develop the rule base for the expert system.

The system monitors in steady-state, transient, and alarm modes. Signals are collected cyclically, and one or more spectra for each sensor are produced. Current vibration spectra can be automatically compared with baseline spectra from (new) equipment, or last-cycle spectra to detect long-term and short-term degradations.

The system employs vibration data analysis and error correction schemes that extract the maximum diagnostic information. These schemes include high-frequency envelope detection, runout correction, rpm variation correction, and fast fourier transform (FFT) processing techniques. Finally, the results of the analysis are assembled to automatically identify the source and seriousness of the vibration level changes.

The software analyzes the spectra, and deems them either normal or abnormal. If abnormal, a diagnostic message is provided to indicate the probable cause; or, if the cause cannot be identified, because diagnosis is not possible, the system presents the information that a skilled diagnostic engineer needs to make a decision.

While the expert system takes the drudgery out of vibration diagnosis by providing the diagnosis automatically, in most cases it will require some additional sensors and a dedicated minicomputer. Moreover, the addition of this new equipment will result in some added maintenance for the instrumentation and the allocation of precious air-conditioned space for the minicomputer. Still, this may be the preferred alternative to periodically performing vibration monitoring with hand-held measurement devices.

Advanced Simulation Technique

Although the AI approach appears to offer the potential for more dependable turbine protection, an objection has been voiced as to the system's "digital" approach to situation assessment. That is to say, the entire range of possible status for the multitude of turbine performance sensors is divided into a rule base of finite size. Even a rule base containing 100,000 entries would be of little use for assessing a particular turbine operational situation if the set of sensor conditions did not match verbatim one of the 100,000 pre-established rules. The 100,001st possible combination of sensor states would require human expert assessment, but this combination of parameters might be intolerant of delay before corrective action is taken.

DOCS

A turbine surveillance system that could comprehensively monitor machine condition, trend parameter excursions, and point decisively to failed components, without depending on a truth table survey or human assessment, might offer even better overall protection.

A technical approach that satisfies these needs is called Disaggregated On-Line Comparative Simulation (DOCS) [8]. In the DOCS approach, failures are detected when the difference between continuously-measured system variables and their corresponding calculated model values are outside preset limits. The causes are located by disaggregating the model into submodels, which results in accurate isolation of failures.

The DOCS principle is illustrated in Figure 9. In this example, the system input, I, is applied to the simulation model of subsystem 1, and the real output of subystem 1 is applied to the model of subsystem 2. If the real output, O_1, differs from the simulated output, OS_1, then the failure is in subsystem 1. Similarly, if O_2 differs from OS_2, then the failure is in subsystem 2.

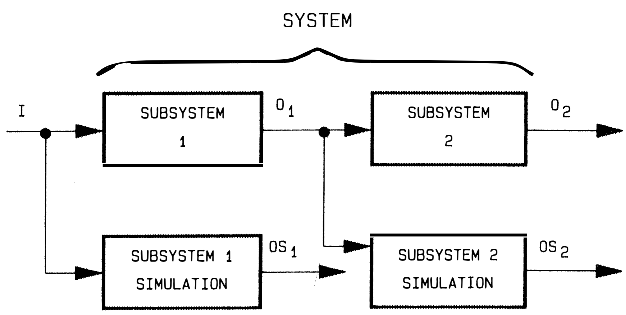

Figure 9. Disaggregated On-Line Comparative Simulation.

In practice, DOCS can be summarized as an organized way of feeding data gathered in real-time through a set of equations to calculate outputs, which are also measurable by sensors. Observed discrepancies between measured and calculated outputs ultimately allow backtracking to the origin of a failure.

The organization comes from the assumption that a subsection is totally isolated from its environment by monitoring all inputs and all outputs. A computer code is then generated that simulates this closed system. Using the actual sensor inputs, the outputs are calculated independent from the rest of the world. Hence, the only time a discrepancy between the measured and calculated outputs can occur is when there is a discrepancy between the subsystem and the model description of the component, which is indicative of a failure in the subsystem.

However, there could be a sensor failure providing a false indication of system trouble. Such a sensor failure can be distinguished from a system failure by removing the questionable sensor's signal from the model. Most of the available sensors on turbines are for the practical uses of turbine monitoring and are not suitable for determining power flow between subsections, as would be required by DOCS. Minimally, a full knowledge of the steam properties, valve positions, and all control signals for all the sections is required. This requires extensive flow, pressure, and temperature measurements, which have to be made independently from each other. All power and mass flows as well as control signals should be measured. If this is not possible, the system would still be applicable, but failures affecting these unmeasured variables would not be detected.

It is believed that the DOCS technique, when fully applied for turbine protection, will have the following advantages:

- Detection of failures—especially useful in detecting failures that are not immediately obvious. For example, turbine blade erosion would initially manifest in slight changes in turbine rotor balance/vibration, though this vibration may be within acceptable limits.
- Location of failures—the disaggregation of the system for simulation allows the operator to quickly key in on the failed component or subsystem.
- Identification and analysis of transients—failures can be detected and located during transient and steady-state operation. Rapidly fluctuating signals can be accommodated.
- Identification sensor failure—the system will be able to distinguish between sensor failures and actual out-of-tolerance turbine operating conditions.
- Monitoring—the system will not only act as a failure detection, it will also monitor system condition and predict future states of the system.

One field application of DOCS has already been attempted with a simplified system model applied to an entire power plant. Taking a small portion of a plant (the turbine) and developing a complete, accurate model holds great possibilities in demonstration of DOCS. This arrangement would not only provide quick diagnosis of system operation, but could offer the operator guidance in his decision making.

CONCLUSIONS

The problem of spurious turbine protection system trips and subsequent plant downtime is not as serious as other operational and maintenance problems in power plants, but it still warrants attention. The annual average of six to eight hours of outage time, per plant, justifies expenditures, in 1987 dollars, of up to $700,000. Equipment and methods are available now whose costs are well within this limit and which can be implemented to improve TPS performance. Further, there are more advanced techniques, under development and/or close to widespread commercial use, which will form the basis for future TPS strategies.

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