EXPERIENCE WITH PERIODIC VIBRATION MONITORING IN FOSSIL POWER STATIONS

by

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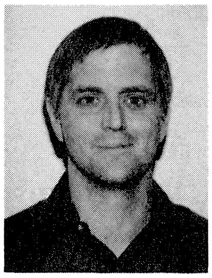

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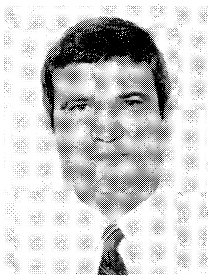
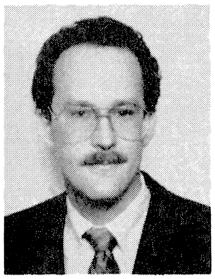


E. Forrest Pardue is the Marketing and Sales Manager for Computational Systems, Incorporated, where he is responsible for vibration monitoring and analysis products promotion, sales, and contract interactions for the domestic and foreign markets. He has a B.S. in Electrical Engineering from North Carolina State University and an M.B.A. from Lynchburg College. After completing his education, Mr. Pardue spent six years performing structural dynamics, finite element analysis, and modal analysis on nuclear reactor systems. He also conducted in-service inspection and vibration monitoring activities on reactor secondary equipment at various nuclear facilities. During the past five years, Mr. Pardue's interests have focused on predictive maintenance program development in industrial and production environments.



Ernest P. Phillips is the owner of Pump & Vibration Consultants. His company provides machinery diagnostics, balancing, predictive maintenance services, and systems to a wide range of industries.

Prior to founding Pump & Vibration Consultants, he was employed as a Service Specialist with the Byron Jackson Pump Division, and later as Manager of Engineering for the Nuclear Division of the Johnston Pump Company. His background in the pump industry as both a troubleshooter and designer has given him unique insight into the causes and corrections of pump vibration.

ABSTRACT

Results are presented from data obtained from the cumulative experience of eight utilities which are conducting periodic, computer based predictive maintenance (PM) programs at their fossil stations. These programs are utilizing a new generation of PM instrumentation that significantly reduces the cost of conducting a program, while improving fault detection effectiveness. A description of the PM program results being achieved is highlighted and some cost/benefit data is presented. Finally, specific monitoring recommendations are presented for boiler feed pumps on information extracted from machinery databases acquired from the participating utilities and monitoring experiences of the authors.

INTRODUCTION

Forced outages and/or load reductions due to failures of rotating equipment are prime contributors to the loss of availability of both fossil and nuclear power stations. Both the Department of Energy and the Electric Power Research Institute (EPRI) have sponsored efforts to demonstrate the potential of vibration signature analysis techniques to predict incipient failures and thereby increase the availability of electric generating stations.

Portable intelligent vibration data collection units, integrated with a host computer executing comprehensive data management and analysis software, have gained widespread attention within the utility industry. Predictive maintenance (PM) programs using this new generation of instrumentation can be implemented with significantly reduced manpower and capital dollar investment.

As a result, a number of utilities have initiated predictive maintenance programs which monitor a broad segment of plant equipment, typically 50–300 machines at a power station. This represents a significant change in the power generation industry; even as recently as 1983, only the most critical equipment was monitored by vibration analysis and the resident vibration expertise was mainly directed at "fighting fires." EPRI Project RP1864-4 is compiling detailed information from utility predictive maintenance programs that have adopted this new instrumentation approach. The eight utilities participating in this study are monitoring 130 generating units at 41 different stations. These utilities are identified in Table 1.

Table 1. Existing Utility Programs Using Automated Predictive Maintenance Systems.

Utility	*Type of Plant*	*Number of Stations/Units*	*Number of Monitored Machines/Points*
Potomac Electric Power	Fossil	5/16	752/3233
Cleveland Electric	Fossil	4/15	269/
Pacific Power	Fossil	2/8	178/897
New Brunswick	Fossil	5/8	265/2650
Commonwealth Edison	Fossil	10/24	1213/14424
San Diego Gas & Electric	Fossil	2/9	102/1484
South California Edison	Fossil	11/48	790/5100
Tennessee Valley Authority	Fossil	1/1	50/190

These programs are collectively monitoring some 47,000 points on 5,000 machines. These utilities have been utilizing their new predictive maintenance instrumentation for more than a year. The study is compiling information that documents the organizational, administrative, and/or analytical methods being used and their effectiveness, with particular emphasis on identifying program costs and benefits. In addition, fault case history data has been collected in an effort to define failure patterns. Finally, machinery database files from six of these utilities have been acquired in order to extract useful fault detection and/or diagnosis criteria for specific equipment types.

ADVANCED PREDICTIVE MAINTENANCE PROGRAMS USING PERIODIC SURVEYS

The new approach that many utilities have adopted for implementing a computer based PM program is described herein. This approach combines the concept of performing periodic vibration surveys manually with the automated analysis performed by an online, computer based monitoring system. This new approach allows complex vibration data to be collected and processed at a rate that is a factor of ten or more greater than that achievable with previous all-manual instrumentation. The new approach retains the automated processing capabilities of on line computer based systems without the high capital investment associated with dedicated sensors and cabling. The general features available in the new PM instrumentation systems will be described.

New PM Instrumentation Systems

The new generation of predictive maintenance systems consists of an integrated hardware/software package which uses a host computer workstation for data storage and diagnostic analysis, coupled with a portable, intelligent data collection device for collecting manual survey data. The host computer (typically an IBM Personal Computer) executes software capable of performing a variety of database management functions, data retrieval and display, and engineering analysis. The instrumentation relies upon a high level of integration between the host computer and the collection device, to optimally distribute both intelligence and portability, so the collection and analysis activities can be performed efficiently and cost effectively. The distribution and flow of information in this approach is illustrated in Figure 1.

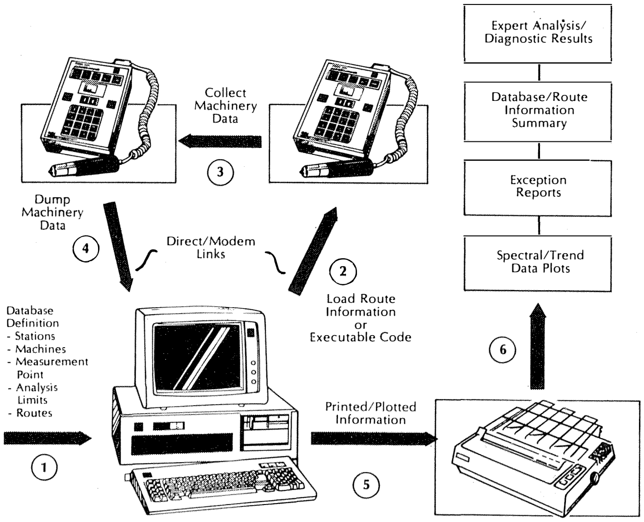


Figure 1. New Generation Automated Predictive Maintenance Approach.

The portable data collection device is a lightweight, battery-powered signal analyzer which can intelligently process and store data. The data collector is capable of performing a variety of machinery measurements as either a routine survey instrument or as a general purpose signal analyzer. When a measurement survey route is loaded into the data collector, the acquisition of detailed vibration data specific to each measurement location is accomplished by simply pressing a button to initiate the measurement. Data collectors currently on the market have a maximum frequency response of 20 kHz and greater than 50 dB of dynamic range. Many of the instruments can calculate an averaged FFT spectrum with up to 400 lines of resolution and store several hundred of these spectra. Other machinery parameters which can be acquired with the data collectors include overall vibration amplitudes, vibration time waveforms, vibration amplitudes in specific frequency bands, phase, DC gap voltage, machine RPM or other process variables, and qualitative observations can be logged. Additionally, many of the data collectors provide live time graphics displays, so that information can be reviewed immediately.

A standard RS232 serial link is used to transfer data between the data collection device and the host computer. Communications can be accomplished either with a direct link or via a modem for remote sites. At 9600 baud, the data for a single measurement point, including a 400-line FFT spectrum, can be downloaded to the host computer in less than one second.

Computer Based Periodic PM Programs

The heart of these PM programs is the software package which executes on the host computer to support the operation of the data collector. This software should (1) allow a machinery database to be created and maintained, (2) allow analysis procedures to be defined, (3) allow measurement route data to be exchanged with the data collector, (4) allow machinery data to be automatically scanned for exceptional values, (5) allow graphical displays to be generated for diagnostic evaluations, and (6) allow stored data to be effectively managed. The decisions regarding what is to be monitored, where it is to be monitored, how it is to be monitored, and how often represent one of the more difficult tasks associated with implementing a program.

It would be desirable to have the judgment of an experienced machinery analyst available for this task. The decisions made at this point can have a significant impact on the ease and effectiveness experienced during routine program execution. A view of the collective judgment exercised by the participating utilities is provided.

Once initial thinking and planning are complete, the process of entering the definition of machines, the measurement locations and routes, and all analysis procedures into the database on the host computer is rather painless. Such information on several hundred machines can be installed in a single day. Data associated with a specific route can now be downloaded into the data collector and routine data collection can begin. The technician follows the measurement route that has been loaded into the meter to the appropriate locations, attaches the transducer, and initiates the measurement. Data and qualitative observations regarding the machinery can also be entered directly through the front panel keypad. At the conclusion of a complete measurement route, the collected data is transferred into the host computer system's database. The computer performs an alarm analysis and generates an exception report indicating those machines with significant changes in their measured characteristics.

The PM software assists diagnostic evaluations by allowing the machinery analyst to display and examine dynamic signal characteristics or long–term performance trends. Nonetheless, the burden of diagnosing machinery faults and determining their severity still rests on the human since no vendor has yet offered an "expert analyst program."

There are several advantages to periodic computer based PM data collection and analysis systems:

- Vibration data of greater detail can be routinely collected with less skilled technicians
- Opportunities are reduced for introducing human error when collecting or recording data.
- The analysis and preservation of survey data (including spectra) are automated, reducing manpower requirements.
- Program personnel can focus more time on investigating and making decisions about potential machine problems due to a reduction in the effort required to manipulate and compare data.
- An automated program does not depend on a "key man" as do most manual programs. Key program personnel can leave the automated program without adversely affecting its future success.
- Standard report formats are established on the computer to facilitate the transmission of the necessary information.
- Vibration databases are centralized and are more readily available for remote interrogation.
- Procedures are more easily standardized between facilities.

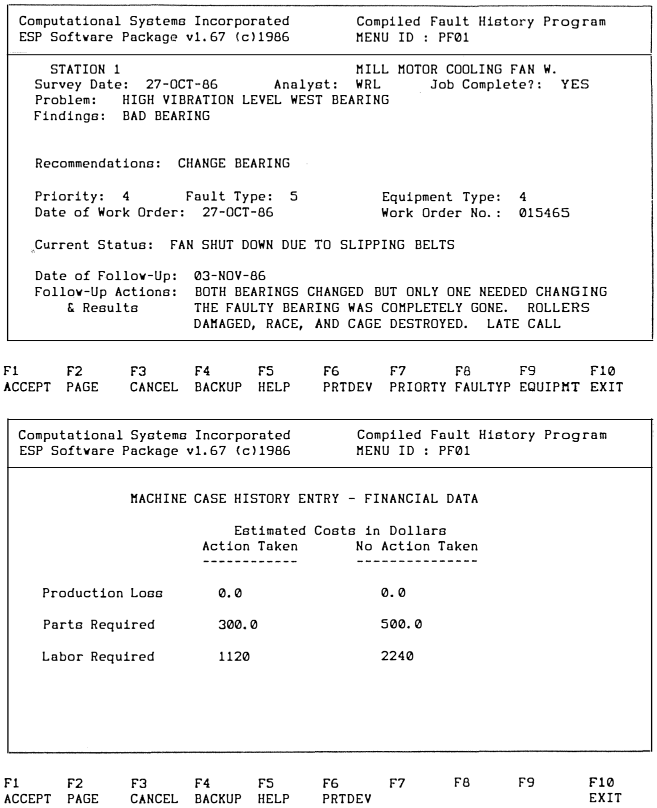
Program Management and Documentation

Predictive maintenance software packages provide significant capabilities for manipulating, analyzing, and storing machinery data and for assisting in fault diagnosis. This software focuses on the technical data and procedures for administering a predictive maintenance program, but does not directly address the need to generate reports and compile data associated with program results.

Inadequate records and information exchange mechanisms can severely limit the productive accomplishments of an otherwise sound program. A compilation of program results is critical for establishing a basis for program continuation and/or enhancements and aids in machinery diagnostics by facilitating access to machinery failure patterns. Furthermore, written communication procedures must be implemented to ensure that recommended actions are visible to both management and the appropriate maintenance personnel.

A maintenance history compilation program, COMPIL, was developed to address the needs of a PM program for managing this information effectively. COMPIL allows machinery maintenance case histories to be entered in a database and generates a set of standard reports to communicate important information. The data maintained by the compilation program allows program performance to be monitored with regard to the accuracy of fault predictions, the effectiveness of repairs, or the disbursement of maintenance dollars. An example of the data requested for a maintenance case history entry is illustrated in Figure 2. A set of standard reports can be automatically generated from the information entered into the program database. The standard reports available are:

- Predictive maintenance survey report
- Problem analysis summary report
- Work request followup report
- Cumulative machine history report
- Specific machine history report
- Fault summary report
- Cumulative equipment summary report
- Cost analysis report



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Computational Systems Incorporated        Compiled Fault History Program
ESP Software Package v1.67 (c)1986        MENU ID : PF01

   STATION 1                              MILL MOTOR COOLING FAN W.
 Survey Date:  27-OCT-86      Analyst:  WRL      Job Complete?:  YES
 Problem:   HIGH VIBRATION LEVEL WEST BEARING
 Findings:  BAD BEARING


 Recommendations:  CHANGE BEARING

 Priority:  4       Fault Type:  5          Equipment Type:  4
 Date of Work Order:  27-OCT-86             Work Order No.:  015465

 Current Status:  FAN SHUT DOWN DUE TO SLIPPING BELTS

 Date of Follow-Up:  03-NOV-86
 Follow-Up Actions:  BOTH BEARINGS CHANGED BUT ONLY ONE NEEDED CHANGING
     & Results       THE FAULTY BEARING WAS COMPLETELY GONE.  ROLLERS
                     DAMAGED, RACE, AND CAGE DESTROYED.  LATE CALL

F1      F2      F3      F4      F5      F6      F7      F8      F9      F10
ACCEPT  PAGE    CANCEL  BACKUP  HELP    PRTDEV  PRIORTY FAULTYP EQUIPMT EXIT
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Computational Systems Incorporated        Compiled Fault History Program
ESP Software Package v1.67 (c)1986        MENU ID : PF01

               MACHINE CASE HISTORY ENTRY - FINANCIAL DATA

                         Estimated Costs in Dollars
                      Action Taken        No Action Taken
                      ------------        ---------------

   Production Loss      0.0                 0.0

   Parts Required       300.0               500.0

   Labor Required       1120                2240

F1      F2      F3      F4      F5      F6      F7      F8      F9      F10
ACCEPT  PAGE    CANCEL  BACKUP  HELP    PRTDEV                          EXIT
```

Figure 2. Example of a Maintenance Case History Entry.

The software was distributed to the utilities participating in this study. It was hoped that the package would facilitate recordkeeping and reporting tasks already in practice and provide a common format in which program results data could be accumulated. COMPIL did have a positive effect toward these goals. Two utilities have adopted COMPIL into their programs and a third utility is maintaining the same data in its own format.

Regardless of whether this compilation software is the means chosen to document this data, specific fault case histories, general fault mode patterns, fault diagnosis accuracy trends, and cost/benefit figures should be accumulated in some form in a mature PM program.

OVERVIEW OF PARTICIPANT UTILITY PROGRAMS

The practices and experiences compiled from the eight utility participants are summarized. Most specific references to the practices of individual utilities have been omitted. All eight supplied detailed information both verbally and in response to a 16 page written survey. Six utilities supplied copies of their PM databases for one or more stations, representing data from some 20 different fossil power stations. Four utilities provided fault compilations resulting from their programs during the past one to three years. These represent a total of 483 fault cases reported by PM survey teams.

What Should Be Monitored, Where, and How Often?

The utilities ranked nine areas of potential financial benefit from the implementation of a periodic PM program. All participants identified increased availability as providing the greatest payback potential. Most expected this to occur from early detection of developing faults, although one participant expected the major share of the increased availability to result from confirming good performance and avoiding time-scheduled maintenance.

The next two items identified as offering large potential paybacks were reduced replacement parts costs and reduced repair labor costs associated with early detection. There was about equal support as to whether parts or labor should be in second position. Interestingly, one participant cited reduced insurance premiums as having the third greatest financial impact within his utility (perhaps others need to contact their carriers).

The expected payback determines the criteria for deciding what equipment should be monitored. Most utilities have attempted to classify the equipment in their plants into three or four categories:

- Critical equipment—Loss of these machines causes a partial load reduction or a plant shutdown.
- Necessary equipment—Loss of these machines does not cause a reduction in load due to one or more redundant spares.
- Machine faults may have high maintenance costs if extended damage or emergency repairs result.
- Auxiliary equipment—Loss of these machines results in operational inconveniences or minor repair costs, since these machines are used only during specific operations or their function can be performed by an alternate system.

Others have proposed slightly different category names or definitions; however, these categories seem to reflect the objective of separating machines that affect availability and machines which may result in high repair costs from other equipment. In the auxiliary equipment, some have suggested a lower horsepower limit (such as 5.0 hp) for determining machines which do not-merit monitoring by the PM program.

A preliminary generic breakdown into these categories of equipment that might be found in a fossil plant is provided in Table 2. Most of the participating utilities are monitoring from 35 to 50 machines per unit.

Table 2. Equipment Monitored in Fossil Utility PM Programs.

Critical Equipment—Loss of these machines will cause a partial load reduction or a plant shutdown.

Generally Accepted

Main Turbines
Generator & Exciters
Boiler Feed Pumps
Induced Draft Fan
Forced Draft Fan
Primary Air Fans

Unit Specific

Pulverizers & Exhausters
Air Heater Drives
Gas Recirculation Fans
River Water Pumps
Circulating Water Pumps
Condensate Pumps
Forced Circulation Pumps
Dry Vacuum Pumps
Main Oil Reservoir Pumps
Sulfer Control System Pumps

Necessary Equipment—Loss of these machines does not cause reduction in load due to one or more redundant spares. Machine faults may have high maintenance costs if extended damage or emergency repairs result.

Main Air Compressor
Instrument Air Compressors
Soot-Blowing Air Compressors
Cooling Tower Fans
SO_2 Booster Fans
Evacuators
Make-up Pumps
Steam Cooling Pumps
Seal Water Pumps
Gland Steam Leak-Off Pumps
Heater Drain Pump
LP Service Water Pumps
HP Service Water Pumps
Cooling Water Pumps
SO_2 Circulation Pumps
Dust Vacuum Pumps
Particulate Circulation Pumps
Oil Cooling Pumps
Stator Cooling Pumps
Bearing Cooling Water Pumps

Auxiliary Equipment—Loss of these machines results in operational inconvenience or minor repair costs since these machines are used only during specific operations or their function can be performed by an alternate system.

Furnace Blower
Flame Scan Blowers
SO_2 Air Blowers
Bunker Exhaust Fans
IP/HP Oil Reservoir Vapor Extractors
Air Preheat Drives
Pump and Heater Sets
Air Temperature Pumps
Demineralizer Booster Pumps
Acid Transfer Pumps
Hydrogen Seal Oil Pumps
Hydrogen Vacuum Pumps
Hydrogen & Air Seal Oil Pumps
Cation Exchange Effluent Return Pumps
Sump Pumps
Slag Tank Overflow Pumps
Screen Wash Pumps
Caustic Transfer Pumps
Ash Sluice Pumps
Make-up Transfer Pumps

Standard practice in periodic survey programs is to monitor both the driver and driven unit in a machine train at each accessible bearing location. The most comprehensive approach would recommend measurements along three perpendicular axes (i.e., horizontal, vertical, and axial) at each measurement site. In many programs, one or more directions are omitted to reduce data collection time, or because the data is believed to be redundant. When only one measurement direction is taken, either the horizontal axis or the direction exhibiting the highest vibration amplitudes is most commonly selected. Another common practice is to take an axial reading at only one position on each machine in the equipment train.

Compared with other industries, utilities do not monitor a particularly large number of machines. This suggests that collecting a more comprehensive set of measurements is justified; ten readings per machine is the average for the participants in this study. Certainly, the machines in the critical equipment category merit acquisition of the most comprehensive data, and machines in the auxiliary equipment could reasonably receive reduced attention.

To reduce the transmitted vibration, measurement locations should be selected to correspond to locations that have the most direct path to the load-bearing elements with a minimum number of assembly interfaces. These locations should be clearly marked, so that all measurements are repeated identically at this location. Some utilities have dimpled or drilled a pilot hole; others have machined flats or glued measurement disks to ensure that measurement positions are precisely located. Some vibration instrument vendors offer mounting pads with mating sensor attachments that provide a highly repeatable quick-connection mechanism. These approaches have not gained widespread acceptance and most utilities collect data with hand-held or magnetically mounted sensors.

The frequency with which periodic surveys are conducted reflects the relative importance assigned to critical equipment or critical generating units. The participant utilities typically monitor critical equipment or units every two weeks. The choice in favor of critical equipment or critical generating stations is determined by whether an in–plant or a corporate survey team collects the data. All other equipment or generating stations are most commonly monitored monthly. Some utilities monitor auxiliary equipment even less frequently. Outside the utility industry, a monthly monitoring schedule is the most common practice when it can be achieved. Another recommendation related to frequency of monitoring is that the monitoring frequency be doubled when an alert level is passed, and doubled again if an alarm level is exceeded. It has also been recommended that machines which are habitual troublemakers be monitored with the same frequency as critical machines.

Machinery Fault Patterns

Four utilities provided lists of faults detected by the periodic PM programs. These lists included about 500 faults. Although this sample of faults is not extremely large, it has been broken down in several ways to identify general patterns. A scatter plot is presented in Figure 3, showing the number of faults detected per year as a function of the number of machines monitored for each unit for which data was reported. For three of the utilities, a best-fit estimate of the average fault detection rate indicates the PM programs find problems in about ten percent of the machines that are monitored yearly. One utility appears to experience problems in its plants much more frequently than the others.

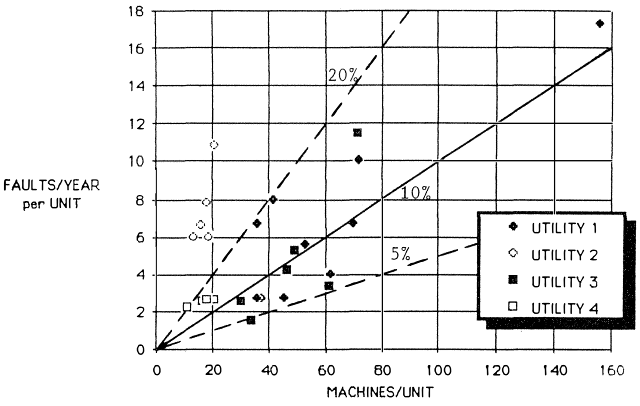


Figure 3. Scatter Plot Illustrating the Relationship Between the Number of Machines Monitored Per Unit and the Number of Faults Detected Per Unit Per Year.

Fault occurrences were classified into general fault categories as a function of the predominant types of equipment being monitored. This data is presented in a cumulative tabulation in Table 3 for all four utilities. In these utilities, 57 percent of the equipment monitored is pumps, 21 percent is fans, and 4 percent is turbines. Logically, pumps and fans experienced a high percentage of the faults detected, 54 percent and 35 percent, respectively. For pumps, the most prevalent fault types were bearings (32 percent), and alignment (six percent). Based on a very small set of data, 65 percent of the problems detected in turbines were due to unbalance. Another interesting figure was that 19 percent of the pump problems were actually associated with the driver, not the pump. In comparison, very few faults were detected in fan motors (three percent). One utility reported 83 faults (which were not included in these tabulations, because the number of each equipment type monitored was not known). However, this data agreed with the general fault patterns identified for pumps, fans, and motors.

Table 3. Cumulative Faults Detected by Periodic PM Programs at Four Fossil Utilities.

	Pumps	*Fans*	*Turbines*	*Other*	*Total*
Machines Monitored	970 (58%)	359 (21%)	63 (4%)	293 (17%)	1685
% of Total Faults	54%	35%	3%	8%	
Faults Reported	221	144	13	35	413
(1) Bearing	71.8 (32%)	45.5 (32%)	0	5.3 (15%)	122.5 (30%)
(2) Unbalance	12.3 (6%)	73 (51%)	8.5 (65%)	5.3 (15%)	99.1 (24%)
(3) Alignment	27.8 (13%)	9 (6%)	0.5 (4%)	5.3 (15%)	42.6 (10%)
(4) Internal	18.5 (8%)	4 (3%)	1 (8%)	0	23.5 (6%)
(5) Foundation	8.5 (4%)	4.5 (3%)	0	9 (26%)	22 (5%)
(6) Resonance	3 (1%)	0	0	1 (3%)	4 (1%)
(7) Others	46 21%)	2 (1%)	0	4 (11%)	52 (13%)
(8) Unknown	33 (15%)	6 (4%)	3 (23%)	5 (14%)	48 (11%)
Involved Driver	42 (19%)	5 (3%)	—	4 (11%)	51 (12%)

Only one utility provided enough data to allow estimates for the accuracy of their predictions to be calculated. This information is presented in Table 4. It indicates that an 80 to 90 percent accuracy rate was achieved in identifying problem machines and recommending maintenance which resulted in improved machinery performance.

Table 4. Accuracy of Fault Identifications in One Utility's PM Program.

	Pumps	*Fans*	*Other*	*Total*
Total Diagnoses:	105	53	9	167
Results:	—	—	—	—
Improved	84	45	—	137 (82%)
Slight Improvement	7	3	—	10 (6%)
No Change	14	4	—	19 (11%)
Worse	0	1	—	1 (1%)

Manpower and Equipment Investments

Most costs associated with conducting a periodic PM program with the new generation of instrumentation are with the personnel requirements. All of the participating utilities, prior to purchasing their new PM instrumentation systems, had invested more than $100,000 in vibration analysis equipment. The total hardware cost of the new instrumentation, including the IBM host computer, was generally less than $18,000.

Portable data collection instruments, together with the associated PM software, vary in price from $9,000 to $15,000. Utility personnel report that data can be collected on up to 800 points per eight-hour shift for machines that are in close proximity. Undoubtedly, the manpower required to collect and analyze the data represents the dominant costs of a program. Instrumentation features which facilitate the collection or analysis process rapidly result in labor savings that offset any small increment in instrumentation costs.

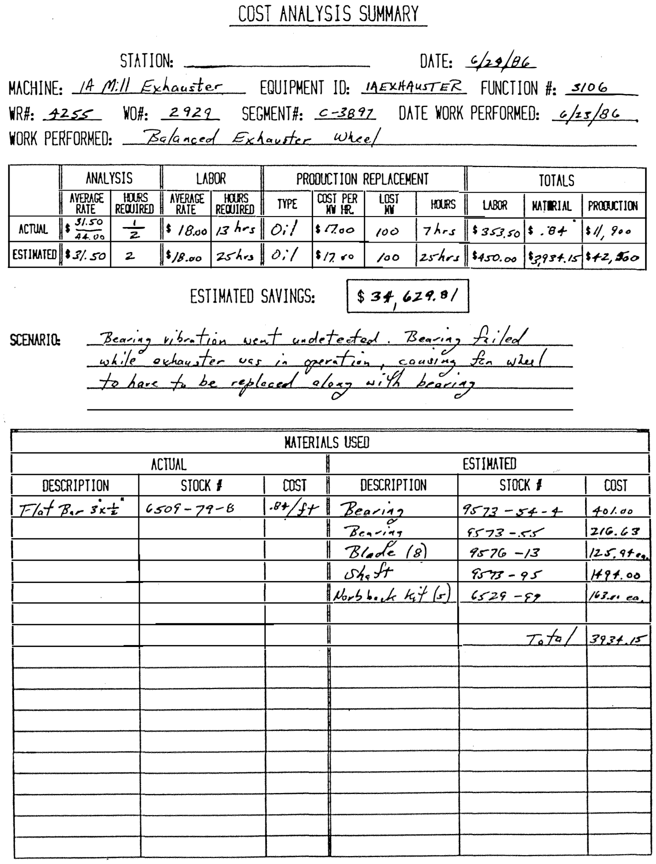
The utilities participating in this study included some programs that are staffed by plant personnel entirely, by corporate staff entirely, or by a combination of plant and corporate staff. The programs with partial or complete corporate staffing are better able to maintain dedicated personnel. Some programs that depend completely on part-time plant personnel never really have enough focused effort to achieve their potential. If conducting a PM program at a single power station does not require full-time attention, then the task of maintaining priority attention for the PM program usually proves difficult. On the average, no utility is committing more than one person per power station.

An effort was made to determine the amount of time required to collect and analyze the data in these programs. For routine data collection, all the data from one physical site is generally collected in a single day (two days at most). This typically represents from 25 to 150 machines and, correspondingly, 150 to 800 points. The analysis time required for performing routine evaluations was reported to range from one to two times the corresponding data collection time.

Time and Cost Savings

Utilities are only beginning to estimate the savings derived from their PM programs. Rightfully, all of the early effort in those programs is focused on establishing the data collection and analysis procedures and finding faults. However, the effective communication of program results can also have a significant impact on program success, particularly for programs conducted or orchestrated by a corporate group. Typically, time savings are reported in a comparative relationship to earlier efforts. One utility documented a savings of 20 hours to 25 hours in analysis time each week over its previous efforts with overall level meters and tape recorders. This was estimated to save $18,000 per year. A second utility had been able to monitor only two to three stations per month, and was able to improve its performance to cover all 11 of its fossil stations in the same period. A third utility experienced greater than a threefold increase in the number of points monitored in a single day with new instrumentation. Two utilities reported being able to routinely collect data on more than 600 measurement points in a single day. These time savings were achieved while at the same time data of equal, and in most cases greater, detail was being collected and processed.

Only one utility could offer estimated cost savings figures. This utility invested the time to take every fault identified during 1986 and to postulate a reasonable scenario of events had the fault gone undetected. The maintenance and replacement power costs associated with the postulated scenario were estimated and compared to those which actually occurred from taking action. The results of this effort are illustrated in Figures 4, 5, and 6. In summary, over $550,000 of savings were estimated during 1986 for one large generating station and over $990,000 for the total of all stations monitored at this utility.



COST ANALYSIS SUMMARY

STATION: ______ DATE: 6/29/86

MACHINE: 1A Mill Exhauster EQUIPMENT ID: 1AEXHAUSTER FUNCTION #: 3106

WR#: 4255 WO#: 2929 SEGMENT#: C-3897 DATE WORK PERFORMED: 6/25/86

WORK PERFORMED: Balanced Exhauster Wheel

	ANALYSIS		LABOR		PRODUCTION REPLACEMENT				TOTALS		
	AVERAGE RATE	HOURS REQUIRED	AVERAGE RATE	HOURS REQUIRED	TYPE	COST PER MW HR.	LOST MW	HOURS	LABOR	MATERIAL	PRODUCTION
ACTUAL	$ 31.50/44.00	1/2	$ 18.00	13 hrs	Oil	$ 17.00	100	7 hrs	$ 353.50	$ .84	$ 11,900
ESTIMATED	$ 31.50	2	$ 18.00	25 hrs	Oil	$ 17.00	100	25 hrs	$ 450.00	$ 3,934.15	$ 42,500

ESTIMATED SAVINGS: $ 34,629.81

SCENARIO: Bearing vibration went undetected. Bearing failed while exhauster was in operation, causing fan wheel to have to be replaced along with bearing

MATERIALS USED

ACTUAL			ESTIMATED		
DESCRIPTION	STOCK #	COST	DESCRIPTION	STOCK #	COST
Flat Bar 3" x 1/2"	6509-79-8	.84/ft	Bearing	9573-54-4	401.00
			Bearing	9573-55	216.63
			Blade (8)	9576-13	125.94 ea.
			Shaft	9573-95	1494.00
			Norbback kit (5)	6529-89	163.00 ea.
				Total	3934.15

Figure 4. Worksheet Used to Estimate Cost Savings Resulting from Detecting a Machine Fault.

MONITORING BOILER FEED PUMPS

One objective of this study is to recommend effective methods for monitoring specific classes of equipment. This section focuses on boiler feed pumps because of their critical role in the plant and their large population in the utility databases acquired in this study. The monitoring guidelines combine the collective experience of the authors and the participant utilities and are presented to allow new PM programs to begin at a technically advanced level. This section is aimed at providing the power plant vibration analyst with the following information:

- Vibration–related machinery faults
- Proper measurement locations
- Important vibration frequency areas to monitor
- Normal vibration levels
- Recommended fault alarm levels
- Typical signature fault patterns
- Case histories.

The following presents a compilation of information gathered from approximately 100 boiler feed pumps at about 20 different fossil power stations.

General Description

The boiler feed pump is the most highly stressed pump within the power generation circuit. Such a pump must operate at high temperatures (300°F to 400°F), high pressure (2700 to

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                    COST ANALYSIS REPORT
                  Report Date:  08-12-1986
                        Station: C

The report listed below is designed to provide an estimated savings
of the vibration monitoring program.  The figures for each machine
are listed with actual costs on top and estimated costs on the line
just beneath.

It should be remembered that, although great care was taken that the
costs would be as representative as possible, the estimates
themselves are predicated on hypothetical events resulting from no
corrective action being taken.

                    Production      Required       Required   Estimated
Machine/Date           Loss           Parts          Labor      Savings

2C Mill Exhauster        0.00        1160.00         277.00    25975.00
   01/22/86          21560.00        4394.00        1458.00

3A Mill Exhauster        0.00        1160.00         273.36    -1433.36
   02/14/86              0.00           0.00           0.00

3C Mill Exhauster     3570.00        1160.00         413.00    37429.00
   02/14/86          36720.00        4394.00        1458.00

2D Mill Exhauster        0.00           0.00          80.00      -80.00
   03/28/86              0.00           0.00           0.00

1B Dome Vacuum Pump      0.00           4.50          66.56     3568.94
   01/22/86              0.00        3500.00         140.00

5-#1 CVS Fan             0.00           8.90          98.06      271.45
   06/09/86              0.00         227.76         150.65

3D Mill Exhauster        0.00           0.46         544.18     5101.84
   06/24/86           4080.00        1160.00         406.48

3A Mill Exhauster     4080.00           0.82         203.24    23127.94
   03/26/86          21560.00        4394.00        1458.00

1B Dome Vacuum Pump      0.00           0.00         133.12     -133.12
   05/22/86              0.00           0.00           0.00

1A Mill Exhauster        0.00         580.00         382.10    26449.90
   06/24/86          21560.00        4394.00        1458.00
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     TOTAL            7650.00        4074.68        2470.62   120277.60
                    105480.00       22463.76        6529.13
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Figure 5. Estimated Cumulative Cost Savings Resulting from the PM Program Conducted at a Utility's Power Station.

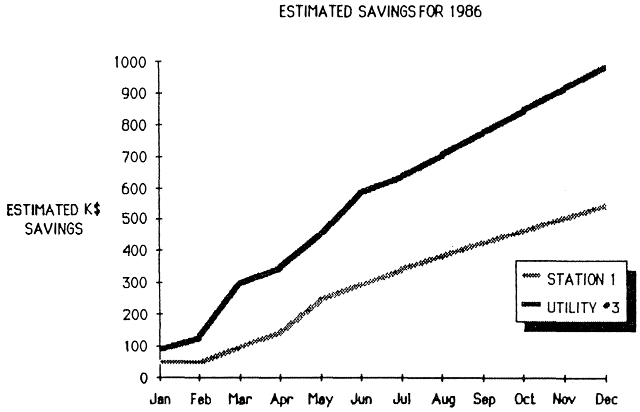


Figure 6. Estimated Savings Resulting from the PM Program at a Fossil Utility During 1986.

4500 psi), and speeds beginning at 3600 rpm under steady-state conditions. It must also be able to withstand transient conditions such as cold startup, reduced flow due to part-load operation, misalignment caused by thermal growth, and thermal shocks due to load rejection or other system upsets [1].

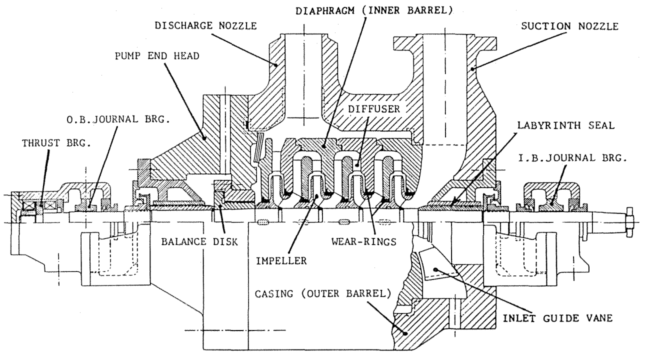


Figure 7. Typical Boiler Feed Pump Monitoring Points.

The typical boiler feed pump in power plant service is a horizontal, multistage, double case, centrifugal pump (Figure 7 [2]). Depending on system design, in order to satisfy feedwater flow requirements and provide plant availability, there may be three 50 percent capacity pumps, two 60 percent capacity pumps, two 100 percent capacity pumps, or one 100 percent capacity pump [3]. High reliability, long life, low sensitivity to transient conditions, and efficiency are key elements in the successful design and operation of feed pumps [4].

The high pressure involved (2700 to 4500 psi) necessitates the use of a forged outer barrel, which is exposed to full discharge pressure. The suction and discharge nozzles may be upward or downward depending on plant design. The inner case forms the internal flow passages and may be either volute or diffuser design. The outer barrel is supported along the horizontal centerline and bolted to support pedestals. Provision to accommodate thermal expansion is provided.

The rotating element consists of the shaft and impellers which may be arranged inline or opposed. The opposed design keeps the hydraulic axial forces produced by the impellers in balance while the inline design requires an axial balancing device such as a balancing drum or disc. There are three types of shaft seals: mechanical, floating ring, and labyrinth seals.

The journal bearings are force feed, oil lubricated, babbitted sleeve type. Some applications require a pivot shoe-type journal bearing. The thrust bearings are double acting pivot shoe-type and are designed to carry axial loads produced by system upsets.

Flexible couplings are required to accommodate changes in alignment due to thermal growth and may be either lubricated gear type or flexible disc/diaphragm-type couplings. The pump driver can be either a constant speed electric motor directly coupled through a gear box or through a variable-speed hydraulic coupling. Alternatively, the pump may be driven by a turbine.

BFP Faults Detectable by Predictive Maintenance Monitoring

Boiler feed pump faults which can be detected by routine PM techniques using frequency-band evaluation include [5]:

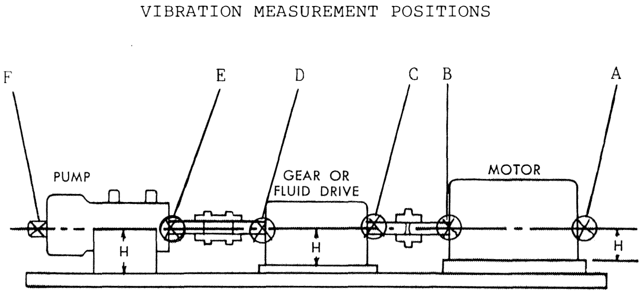
- Hydraulically induced vibration
- Structural vibration
- Control system faults
- Oil whip
- Rubbing
- Structural resonance
- Rotating element unbalance
- Hydraulic unbalance
- Misalignment
- Looseness
- Fluid column resonance
- Bearing degradation

Boiler feed pump faults which *cannot* be found by routine vibration monitoring include seal wear, cavitation, impeller cracks, and shaft cracks.

Recommended Monitoring Approach

The following specific recommendations are offered with regard to monitoring boiler feed pumps. These recommendations combine the collective experience of the authors and the practices of the participant utilities.

Where to monitor. Predictive maintenance monitoring should be performed at each bearing in the machine train. Radial measurements should be taken both horizontally and vertically. The horizontal measurement is the most important and, in a properly running machine, should be higher than the vertical measurement by 20 percent to 50 percent. Since the BFP is considered a critical machine, it is recommended that vertical measurements be taken, because they can occasionally signal a fault not seen in the horizontal measurement. A single axial reading on each component is sufficient on a BFP machine train. Typical BFP monitoring points are shown in Figure 8.



A - Motor outboard horizontal
vertical
axial

B - Motor inboard horizontal
vertical

C - Fluid drive input horizontal
vertical
axial

D - Fluid drive output horizontal
vertical

E - Pump inboard horizontal
vertical

F - Pump outboard horizontal
vertical
axial

Figure 8. Typical Boiler Feed Pump Layout.

How to monitor. Boiler feed pump faults typically appear as distinct peaks or patterns between 2 Hz and 10 × rpm [6]. The key to early detection of BFP mechanical problems lies with resolving the machine's vibration into several frequency bands, with each frequency band bracketing a fault or set of faults. Recommended BFP frequency bands are given in Table 5.

The upper frequency (F_{max}) required for monitoring is 10 × rpm (for a 3600 rpm machine, 10 × is 36,000 rpm or 600 Hz). A high-frequency band between 1 kHz and 20 kHz allows monitoring for cavitation if temporary cavitation is a problem.

Boiler feed pumps are generally variable speed machines. When collecting periodic predictive maintenance vibration information, there is no assurance that the pump will be running at the same speed each measurement period. Due to this potential speed change, the data collection technique should properly adjust each frequency band in relationship to the machine turning speed. This technique is called order normalization. The recommended predictive maintenance monitoring frequency bands with each band's recommended alarm levels are shown in Figure 9.

Table 5. Recommended Boiler Feed Pump Measurement Frequency Bands.

Frequency Band	*Lower and Upper Frequency*
Subharmonic	2 Hz to 0.9 × rpm
Running Speed	0.9x to 1.1 × rpm
2nd harmonic	1.1x to 2.1 × rpm
>2x	2.1x to 10.1 × rpm
Vane pass	Encloses vane pass #vanes × rpm (typically 5 or 7)
High frequency	1 kHz to 20 kHz for detection of cavitation

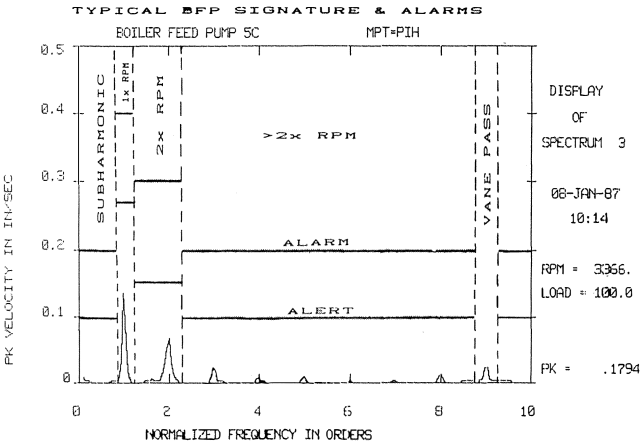


Figure 9. Recommended Predictive Maintenance Frequency Bands and Associated Alarm Levels.

How often to monitor. Monthly BFP monitoring should detect most faults at least two to three months ahead of failure. Due to the importance of the pump, many successful programs are monitoring at two-week intervals. Occasionally, severe degradation occurring within a one-month period has been reported. Once degradation is suspected, surveillance should be increased to weekly. A sample trend of a developing BFP outboard bearing fault is provided in Figure 10.

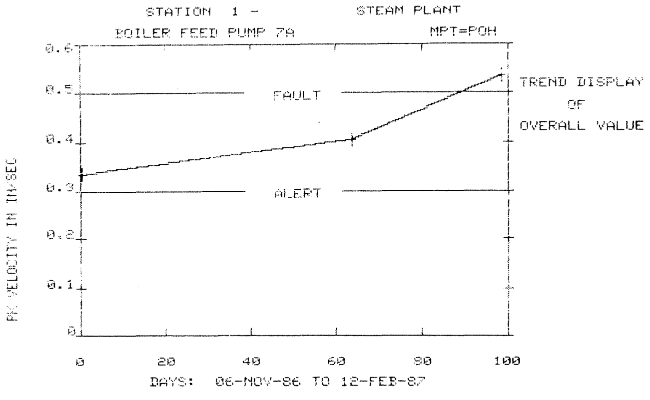


Figure 10. Trend of Outboard Bearing Vibration Rebuild Showing Bearing Degradation.

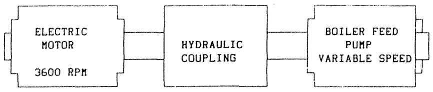
Normal Vibration Levels

Normal boiler feed pump vibration levels have been determined by averaging the survey population of similar machines. The tabulation of normal levels has been divided into electric motor-driven units and turbine-driven units. This division is necessary due to the significant speed an/or design size difference between the common types of BFP.

Normal BFP vibration levels are summarized in Figure 11. This figure presents BFP vibration levels in the significant vibration frequency bands discussed above. Note that it is *not sufficient* to monitor only overall vibration levels for routine BFP monitoring. Frequency band-specific vibration data provides the sensitivity necessary to detect the less energetic faults before they become serious and immediately threatening.

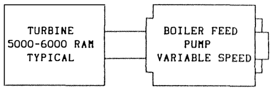
BOILER FEED PUMP VIBRATION SUMMARY

ELECTRIC MOTOR DRIVEN UNITS



Average Vibration Levels
In/Sec Peak Velocity

Frequency Band	Motor Outboard Radial	Motor Axial	Motor Inboard Radial	Coupling Motor Side Radial	Coupling Axial	Coupling Pump Side Radial	Pump Inboard Radial	Pump Axial	Pump Outboard Radial
Overall	0.117	0.124	0.118	0.168	0.104	0.187	0.117	0.092	0.130
Subharmonic	0.015	0.012	0.012	0.032	0.023	0.033	0.021	0.014	0.022
1x RPM	0.070	0.076	0.068	0.133	0.071	0.141	0.066	0.038	0.087
2x RPM	0.070	0.064	0.068	0.051	0.041	0.056	0.052	0.031	0.053
>2x RPM	0.061	0.073	0.067	0.083	0.060	0.104	0.079	0.077	0.078



Average Vibration Levels
In/Sec Peak Velocity

Frequency Band	Turbine Outboard Radial	Turbine Inboard Radial	Pump Inboard Radial	Pump Axial	Pump Outboard Radial
Overall	0.076	0.164	0.239	0.161	0.234
Subharmonic	0.048	0.102	0.110	0.055	0.102
1x RPM	0.051	0.128	0.131	0.049	0.116
2x RPM	0.026	0.056	0.081	0.074	0.071
>2x RPM	0.014	0.000	0.146	0.123	0.161

Note 1: Radial measurment shown is horizontal direction for a normal BFP. Vertical measurements are typically 50-80% of horizontal.

Note 2: Turbine driven BFPs typically have higher vane-pass and low-end subharmonic vibration than electric driven BFP's.

Figure 11. Boiler Feed Pump Vibration Summary.

Recommended Alarm Levels

Many organizations have issued standards for classifying pump vibration levels. These standards can be confusing because they present the levels in many different ways. For example, some standards cite case readings while others cite shaft readings. A summary of several standards applicable to boiler feed pumps is provided in Table 6 [7, 8].

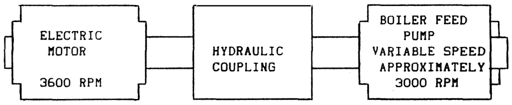
Table 6. Overall Vibration Standards Summary.

Standard	*Measurement*	*Alert Level*	*Alarm Level*
Hydraulic Institute 14th Edition	casing	0.3*	—
ISO 2372	casing	0.25	0.6
EPRI FP 754	shaft	0.5	0.8
API 610 6th Edition	shaft	0.4	—
Rathbone Chart	casing	0.3	0.6

*Filtered reading valid 2,000 to 20,000 CPM

Computational Systems has established a set of bearing cap limit values that are frequency-specific. These recommendations are derived from the normal range of variation in the population of pumps available, amplitudes experienced during fault conditions, and previous industry standards. These limit guidelines are provided in Figure 12.

RECOMMENDED ALARM LEVELS
Casing Measurement - Velocity In/Sec Peak



	Radial Motor Driven		Radial Turbine Driven		Axial All BFP Units	
Frequency Band	Alert	Alarm	Alert	Alarm	Alert	Alarm
Overall	0.25	0.45	0.30	0.50	0.20	0.35
Subharmonic	0.10	0.20	0.15	0.25	0.05	0.15
1x RPM	0.25	0.40	0.25	0.40	0.20	0.35
2x RPM	0.15	0.30	0.20	0.35	0.15	0.25
>2x RPM	0.10	0.20	0.25	0.50	0.10	0.20

The above levels are applicable to the driver and coupling unit as well as the BFP bearings caps.

Figure 12. Recommended Alarm Levels for Boiler Feed Pumps.

The company did not provide recommended alarm levels for the frequency band bracketing pump vane pass, because vane pass amplitude is machine-design specific. Most electric motor-driven BFPs have normally low vane pass amplitudes, while turbine driven units vary widely with manufacturer and design. Vane pass frequency amplitude can also be influenced by piping layout and operating flow. Normal vane pass amplitude is best determined by comparing values from a group of similar machines and observing individual machines for normal changes due to operating conditions.

Diagnostics

After a predictive maintenance program warns of a potential boiler feed pump problem, a diagnostic examination is performed to determine the type and severity of problems present in the machine. Diagnostic work requires examination of a full vibration signature and frequency band–specific trends. The signature is used to determine the type of problem and its current severity. The trend is required to determine the rate of degradation. Boiler feed pump faults and the way they appear in a signature are summarized in Table 7 [1] and Figure 13 [1].

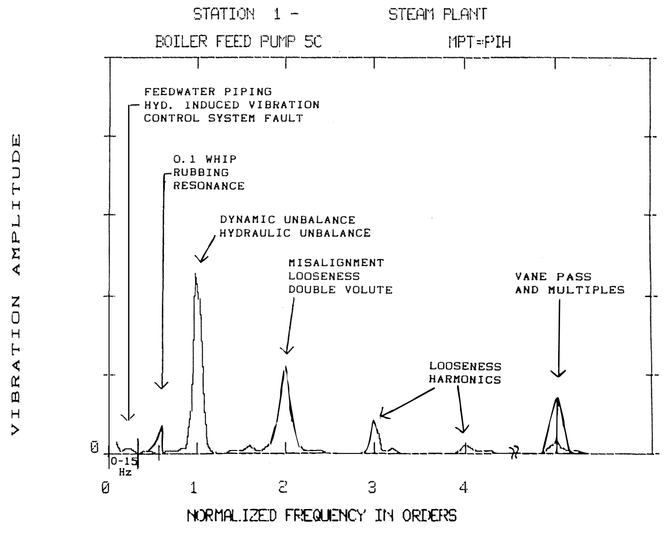


Figure 13. Major Vibration Components for Boiler Feed Pumps.

Table 7. Summary of Boiler Feed Pump Faults.

Frequency	*Probable Cause*	*Checks/Corrective Action*	*Remarks*
SUBHARMONIC			
0-15 Hz	Hydraulically induced a. Low suction pressure b. Turbulence in pipe c. Recirculation	1. Check strainer, valve position, supply system. 2. Check suction pipe for straight, uniform flow to pump. 3. Check flow; should be ±10 percent of design point.	Amplitude fluctuates, can produce high axial shaft and casing vibration; varies with flow.
0.4-0.45 rpm	Oil whirl	Change oil viscosity; redesign bearing—pressure dam or pivot shoe.	
0.5 rpm	Structural resonance caused by rubs and induced hydraulically	1. Relieve rub. 2. Same as 0-15 Hz (3)	Rubs can also produce 1× and high harmonics.
AT RUNNING SPEED			
	Unbalanced rotating element.	Dismantle and inspect.	1× always present, sometimes dominant. Varies with square of speed. (Wear produces gradual change, step change for broken impeller or foreign matter).
	a. Excessive residual unbalance.		
	b. Impeller damage; wear, broken, foreign matter.	Check impeller symmetry.	
	c. Hydraulic unbalance.	Check for proper fit or missing bolt.	
	d. Coupling.		
	Bent shaft.	Check 180-degrees out of phase axially.	Can also produce 2×, varies with square of speed and preload.
	Driver.	Run driver uncoupled; correct as necessary.	
	System resonance.	Measure frequency of mounted system; modify structure.	
	Misalignment.	Check alignment under operating conditions.	Thermal expansion of pump/driver is often different than calculated value. High axial vibration.
2× RUNNING SPEED			
	Misalignment.	Check alignment under operating conditions.	1× may also be present.
	Looseness.	Check bearing fit.	
HARMONICS>2×			
	Looseness.	Check bearing and other mechanical interfaces.	2×, 3×, 4×, if amplitudes are significant. (Low-level harmonics are normal).
RPM × NUMBER OF IMPELLER VANES			
	Hydraulically induced.		
	1. Flow beyond ±10% design point.	1. Check system operation.	
	2. Fluid column resonance.	2. De-tune by changing speed, number of vanes on impeller or pipe length. Install acoustic filter.	2. Variable speed units will normally exhibit fluid column resonance at some speed, hopefully out of the normal operating range.
	3. Bearing bracket resonance.	3. Check bearing bracket resonance frequency; modify as necessary.	3. May be resonant horizontally or vertically.

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ACKNOWLEDGEMENT

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